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LAKE ERIE WATER LEVEL STUDY. APPENDIX E. POWER.(U)

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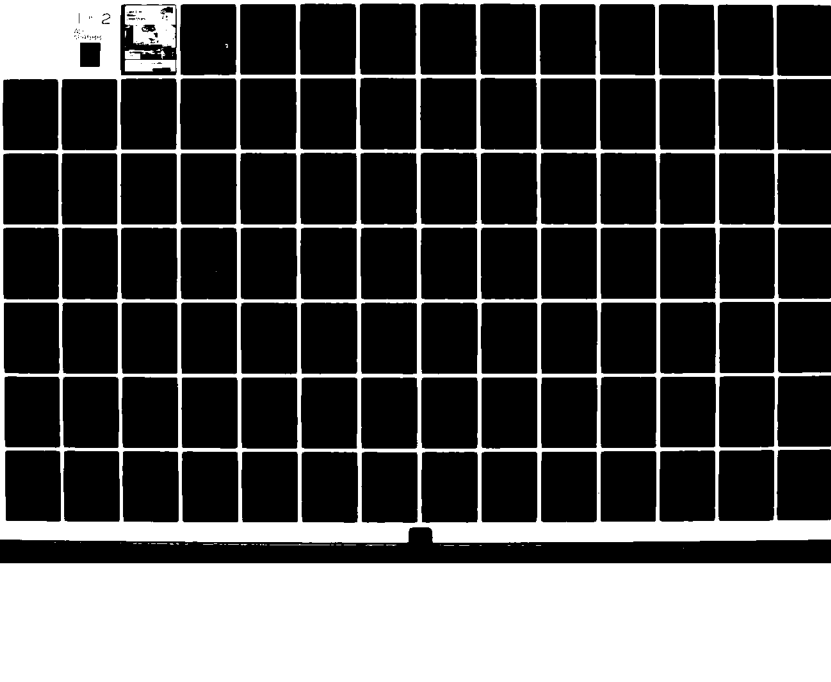

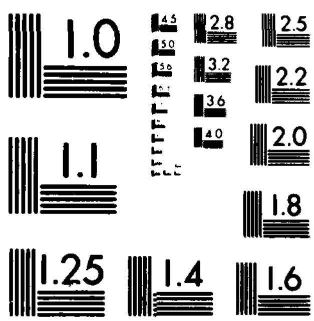

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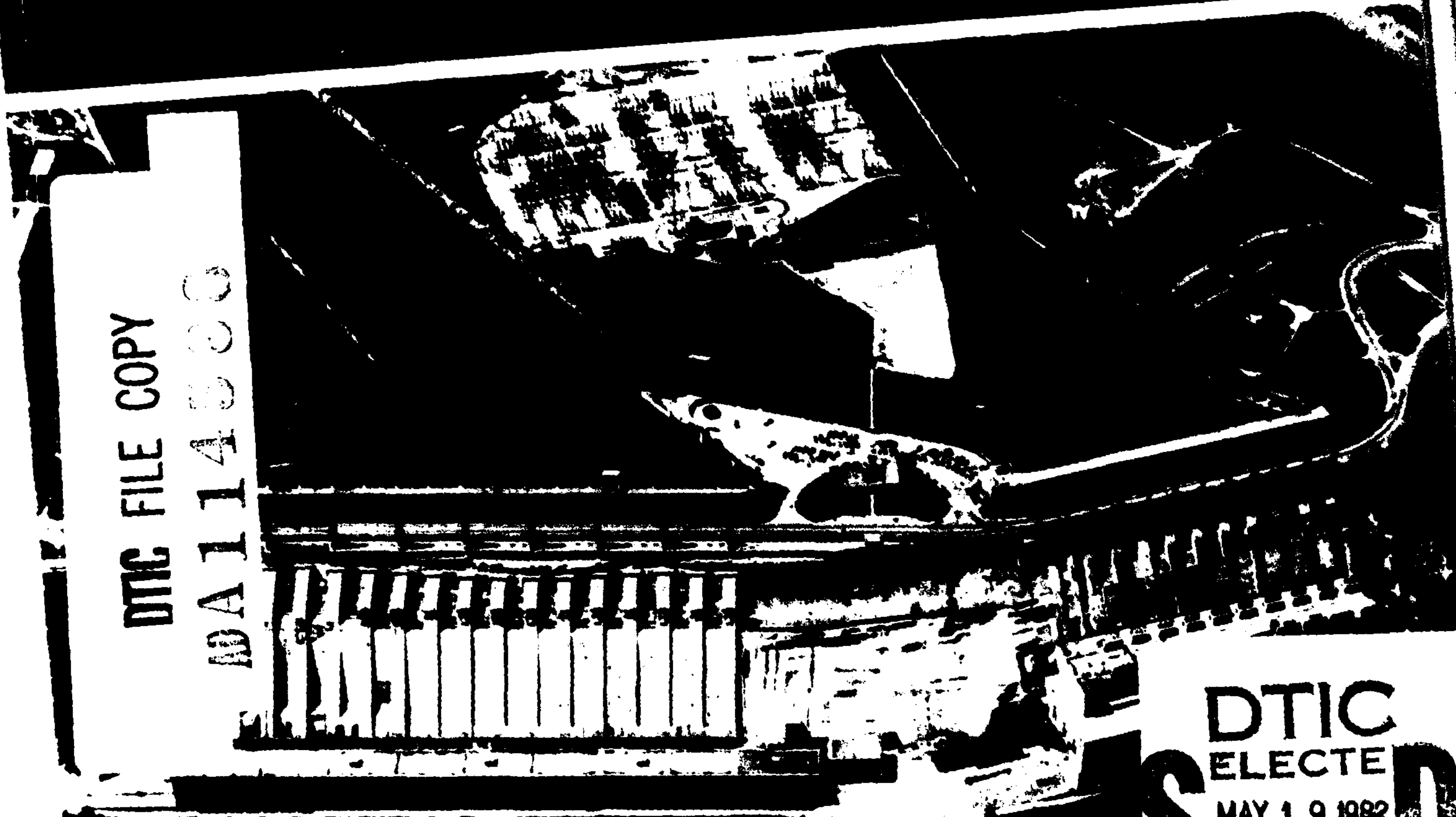
Lake Erie Water Level Study



Appendix [illegible]
Power

International Lake Erie Regulation Study Board
International Joint Commission
July 1981

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This appendix presents the results of the studies on the effects of limited regulation of Lake Erie on hydroelectric power generation. These studies were undertaken by the International Lake Erie Regulation Study Board. The Board was established by the International Joint Commission in 1977 to conduct the study as a result of the reference from the Governments of Canada and the United States. next page

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20. The purpose of the studies was to determine the economic effects of changes in levels and flows as a result of limited regulation of Lake Erie. This appendix contains the study results of the effect on the generation of hydroelectric power on the connecting channels of the Great Lakes and on the St. Lawrence River.

The methodologies used in evaluating the effects of the various regulation plans indicate the benefits or losses to hydroelectric power generation in terms of energy and capacity resulting from changes in levels and flows. The methods used in the evaluation were those used in current economic studies by the power entities involved.

APPENDIX E

POWER

LAKE ERIE REGULATION STUDY

REPORT

TO THE

INTERNATIONAL JOINT COMMISSION

BY THE

INTERNATIONAL LAKE ERIE REGULATION

STUDY BOARD

(UNDER THE REFERENCE OF FEBRUARY 21, 1977)

JULY 1981

SYNOPSIS

This appendix presents the results of the studies on the effects of limited regulation of Lake Erie on hydroelectric power generation. These studies were undertaken by the International Lake Erie Regulation Study Board. The Board was established by the International Joint Commission in 1977 to conduct the study as a result of the reference from the Governments of Canada and the United States.

The purpose of the studies was to determine the economic effects of changes in levels and flows as a result of limited regulation of Lake Erie. This appendix contains the study results of the effect on the generation of hydroelectric power on the connecting channels of the Great Lakes and on the St. Lawrence River. The studies of the other economic effects, namely: coastal zone, commercial navigation, recreational beaches and boating are contained in separate appendices.

The methodologies used in evaluating the effects of the various regulation plans indicate the benefits or losses to hydroelectric power 3eneration in terms of energy and capacity resulting from changes in levels and flows. The methods used in the evaluation were those used in current economic studies by the power entities involved.

Lake Erie regulation plans, designated 25N, 15S and 6L, were selected by the Board and evaluated for 3 categories of Lake Ontario regulation. The evaluation process basically compared the effects of the levels and flows that could be expected under these plans, with those that would be expected under a basis-of-comparison.

The results of the entire studies as well as conclusions and recommendations are provided in the Board's main report.

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APPENDIX A - LAKE REGULATION

A detailed description of the various factors which govern the water supply to the Great Lakes - St. Lawrence River System and affect the response of the system to this supply along with documentation of the development and hydrologic evaluation of plans for limited regulation of Lake Erie.

APPENDIX B - REGULATORY WORKS

A description of design criteria and methods used and design and cost estimates of the regulatory and remedial works required in the Niagara and St. Lawrence Rivers to facilitate limited regulation of Lake Erie.

APPENDIX C - COASTAL ZONE

A documentation of the methodology developed to estimate in economic terms the effects of changes in water level regimes on erosion and inundation of the shoreline and water intakes and of the detailed economic evaluations of plans for limited regulation of Lake Erie.

APPENDIX D - COMMERCIAL NAVIGATION

A documentation of the methodology applied in the assessment of the effects on shipping using the Great Lakes - St. Lawrence navigation system as a consequence of changes in lake level regimes and the evaluation of the economic effects on navigation of regime changes that would take place under plans for limited regulation of Lake Erie.

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APPENDIX E - POWER

A documentation of the methodology applied in the assessment of the effects on hydroelectric power production at installations on the outlet rivers of the Great Lakes and of the detailed economic evaluation of the effects of plans for limited regulations of Lake Erie on the capacity and energy output of these installations.

APPENDIX F - ENVIRONMENTAL EFFECTS

A documentation of the qualitative assessment of the effects of plans for limited regulation of Lake Erie on fish, wildlife, and water quality within the lower Great Lakes and the St. Lawrence River.

APPENDIX G - RECREATIONAL BEACHES AND BOATING

A documentation of the methodology applied in the assessment of the effects of plans for limited regulation of Lake Erie on beaches and recreational boating activities, along with a detailed economic evaluation, within the lower Great Lakes and the St. Lawrence River.

APPENDIX H - PUBLIC INFORMATION PROGRAM

A documentation of the public information program utilized throughout the study to inform the public of study activities and findings and provide a vehicle for public comment on the study.

Section 1

INTRODUCTION

1.1 General

By the terms of the Reference of February 21, 1977, the Governments of Canada and the United States requested the International Joint Commission (IJC) " . . . to determine the possibilities for limited regulation of Lake Erie . . . In particular, this study should examine into and report upon the effects of such limited regulation with respect to:

(1) domestic water supply and sanitation
(2) navigation
(3) water supply for power generation and industrial purposes
(4) agriculture
(5) shore property, both public and private
(6) flood control
(7) fish and wildlife and other environmental aspects
(8) public recreation
and
(9) such other effects and implications which the Commission may deem appropriate and relevant".

The International Lake Erie Regulation Study Board was established by the International Joint Commission on May 3, 1977, to undertake "...the necessary investigation and studies and to advise the Commission on all matters which it must consider in making its reports to Governments . . ."

This Appendix forms part of the final report of the International Lake Erie Regulation Study Board to the International Joint Commission. It describes the hydroelectric power installations on the connecting channels of the Great Lakes and on the St. Lawrence River. It also contains the evaluation of various Lake Erie regulation plans in terms of their effects on capacity and energy outputs of the installations and the monetary values of any changes on these two components.

1.2 Organization

The International Lake Erie Regulation Study Board established a Working Committee to assemble the data, and conduct studies necessary to answer the Reference. The Working Committee established Subcommittees for each major phase of the study. The Power Subcommittee was composed of three members. A list of the Subcommittee members is provided in Annex A. An English/metric conversion table is contained in Annex B.

The Power Subcommittee's assignment was to develop the necessary methodology to evaluate the effect of limited regulation of Lake Erie on hydroelectric power generation throughout the Great Lakes - St. Lawrence River System and to make the necessary corresponding economic evaluations.

1.3 Procedure of Power Study

Hydroelectric power would be affected by regulation of any or all of the Great Lakes since power generating facilities are located on all the international connecting and outlet channels of the Great Lakes except the St. Clair and Detroit Rivers. Determination of the effects of regulation on hydroelectric power installations utilizing the levels and flows of the Great Lakes system, under the basis-of-comparison conditions and under the regulation plans for Lake Erie (25N, 15S or 6L) under Category 1, 2, and 3 conditions for Lake Ontario was carried out by the Power Subcommittee.

The determination of the effect of a regulation plan on hydroelectric power is generally divided into two parts; the effect on dependable capacity and energy output; and second, the monetary evaluation of any changes in these two components measured by the replacement costs. Ice conditions limit the flow at the time that the Hydro Quebec system experiences peak load; therefore, no peak capacity benefit or loss is expected and only the effects of regulation on energy production were evaluated.

In determining the effect of a regulation plan on hydroelectric power, the results of operation under a plan were compared with results under basis-of-comparison conditions, and in the case of Category 3, an adjusted basis-of-comparison. Complete descriptions of both the basis-of-comparison and the regulation plans are given in the main report and Appendix A - Lake Regulation. They are described in part, as follows:

(1) The basis of comparison consists of Lakes Superior and Ontario regulated according to methods presently in effect which are Plan 1977 and Plan 1958-D with discretion, respectively, and Lakes Michigan-Huron and Erie unregulated. The outlet conditions for Lake Huron and for Lake Erie are those of 1962 and 1953 respectively.

(2) Under the regulation plans the outlet capacity of Lake Erie would be increased by three alternative control structures; one in the Niagara River (25N) and two in the Black Rock Canal (15S and 6L). The structure would permit additional flow to be discharged from Lake Erie when the supply to the upper lakes is above normal. For each of the above alternatives, the effect on Lake Ontario has been treated as follows: Under Category 1, Lake Ontario would be regulated under Plan 1958-D with discretionary deviations the same as the basis-of-comparison. Under Category 2, Plan 1958-D was modified to produce Lake Ontario levels and outflows similar to those experienced under actual operation without Lake Erie regulated. Under Category 3, the St. Lawrence River channel capacities and the regulation plan would be altered to satisfy the stage criterion contained in the present Lake Ontario IJC Orders of Approval.

(3) For the basis-of-comparison and each regulation plan, it was assumed that the above conditions, modified by present diversions into and out of the lakes, and by estimated 1985 navigation flow requirements

for lockages past the control structures, would apply at a constant rate over the 77 year period (1900-1976). The estimated 1985 navigation requirements were based on the traditional navigation season and do not allow for the requirements of winter navigation.

This appendix presents the methods employed for computing and evaluating the effects of the various regulation plans under load and power supply conditions estimated to be in effect from 1985 through 2034 on all related existing hydroelectric installations in Canada and the United States on the St. Marys River at Sault Ste. Marie, on the Niagara River near Niagara Falls and on the St. Lawrence River near Cornwall and Beauharnois.

The existing power facilities have a total installed capacity of about 8,000,000 kilowatts (kW) of which 60 percent are in Canada and 30 percent are in the United States.

Using the methodology described in this appendix, computer programs were developed for the determination of peak and energy outputs. A copy of each computer program together with operating instructions are contained in Annex D which is bound separately.

Section 2

ST. MARYS RIVER POWER PLANTS

2.1 General Description

The St. Marys River forms the outlet of Lake Superior. From Whitefish Bay, at the east end of Lake Superior, the river flows in a general southeast direction to Lake Huron, a distance of approximately 70 miles. From its headwater on Whitefish Bay to its outlet on Lake Huron, the river falls about 22 feet, most of which (20 feet) occurs in the mile long St. Marys Rapids at Sault Ste. Marie, Michigan and Ontario. At Sault Ste. Marie various man-made facilities have been constructed beginning in 1887 and consist of navigation locks, hydroelectric power plants and compensating works. Since 1921, these facilities enabled complete control under the jurisdiction of the IJC, of the outflow from Lake Superior. All water flowing out of Lake Superior through the St. Marys River passes through one of these facilities. The general arrangement of the existing U.S. plants, the redeveloped Canadian site, and the water level gauges used in the computations are shown in Figure E-1.

2.1.1 Canadian Power Plant

This study was undertaken assuming redevelopment of the Great Lakes Power (GLP) Corporation power site, which is scheduled for completion in 1982. Each of the three new bulb turbines to be installed at the GLP plant will be rated at 18 MW (turbine output), a rated flow of 12,450 cfs and rated net head of 18.7 feet. The total useable flow capacity of about 37,000 cfs is approximately double the capacity of the old plant.

2.1.2 United States Plants

There are two hydroelectric power plants located on the United States side of the St. Marys River, with a combined rated capacity of 59,600 kW and a corresponding flow of 43,200 cfs. The United States Government plant, which contains four units and is located at the foot of the rapids, has a total capacity of 16,400 kW, and a head of about 18.7 feet. The plant also has one unit located at the head of the rapids with a total capacity of 2,300 kW; all water used is taken from the same diversion canal and totals approximately 12,700 cfs at plant capacity. The Edison Sault Electric Company plant, located below the rapids, is served by a 2-1/2 mile long diversion canal. This plant has a total capacity of 41,300 kW at a head of 18.5 feet with a water usage of approximately 30,500 cfs at rated plant capacity.

2.2 Assumptions

The assumptions adopted for computing the total energy and peak capacity outputs for any given regulated monthly mean Lake Superior outflow and level and corresponding Lake Huron level are given in the following subsections:

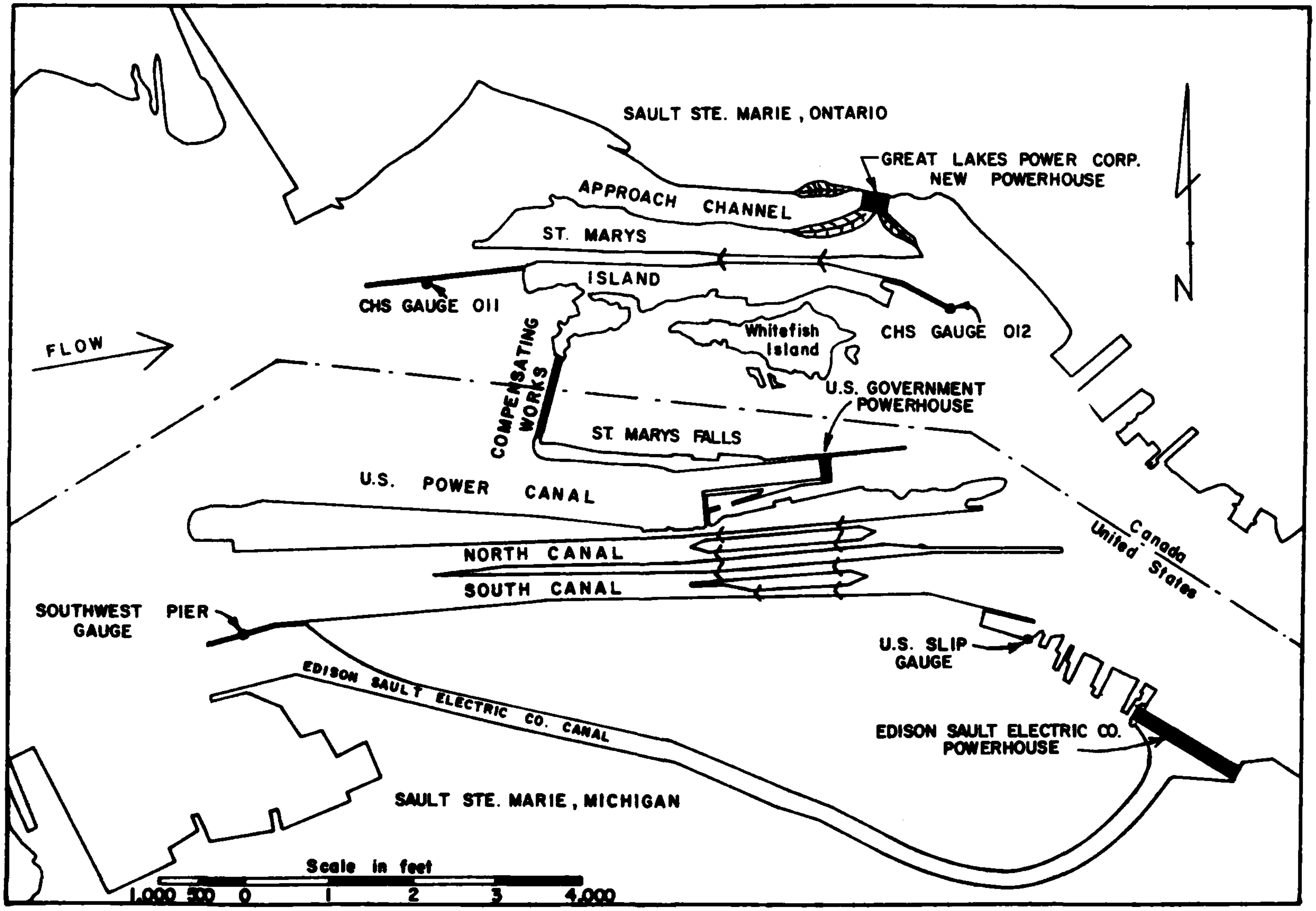


FIGURE E-1

ST. MARYS RIVER AT SAULT STE. MARIE

2.2.1 General

(1) The estimated 1985 navigation flow requirements by months are:

January	200 cfs
February	100 cfs
March	100 cfs
April	500 cfs
May	1250 cfs
June	1350 cfs
July	1650 cfs
August	1700 cfs
September	1400 cfs
October	1150 cfs
November	1100 cfs
December	400 cfs

(2) Flow requirement for the rapids below the compensating works is set constant at 2000 cfs.

2.2.2 Canadian Plant

(1) The plant will be operated on a run-of-river basis; hence, in any month, peak capacity and the rate at which energy is generated are the same.

(2) The flow available for Canadian hydroelectric use is taken as the lesser of the maximum capacity of the redeveloped Canadian plant or the Canadian share computed as:

$$Q_c = \frac{Q_o - Q_m - 2000}{2}$$

where Q_c = Canadian diversion in cfs,

Q_o = Lake Superior mean monthly flow in cfs,

Q_m = Estimated navigation flow requirement in cfs, and

2000 = Spill through compensating works in cfs.

2.2.3 United States Plants

(1) The permissible diversion by U.S. plants is assumed to be the greater of the two amounts (limited by the capacity of the plant) computed as:

$$Q_{us} = \frac{Q_o - Q_m - 2000}{2} \quad \text{or}$$

$$Q_{us} = Q_o - Q_m - Q_c - 2000$$

where Q_{us} = United States diversion in cfs, and

Q_o, Q_c, and Q_m are as defined in Subsection 2.2.2

2.3 Methodology for Determining Capacity and Energy Output

The methods used to compute power output from the St. Marys River plants have been developed by Ontario Hydro and the U.S. Army Corps of Engineers, Detroit District, in co-operation with the Great Lakes Power Corporation and their consultant, Acres Consulting Services Limited, and the Edison Sault Power Company. The methods outlined below compute the output from the redeveloped Canadian plant and the existing U.S. plants under the basis-of-comparison conditions of levels and flows, and the output which would result had a given regulation plan been in operation over the same period. The general approach employed is as follows:

(1) Determine the head loss between Lake Superior and the forebay of the plants to obtain forebay level.

(2) Determine the head loss between the tailrace of the plants and Lake Huron to obtain tailwater level.

(3) Compute head on the plant as the difference between forebay and tailwater levels.

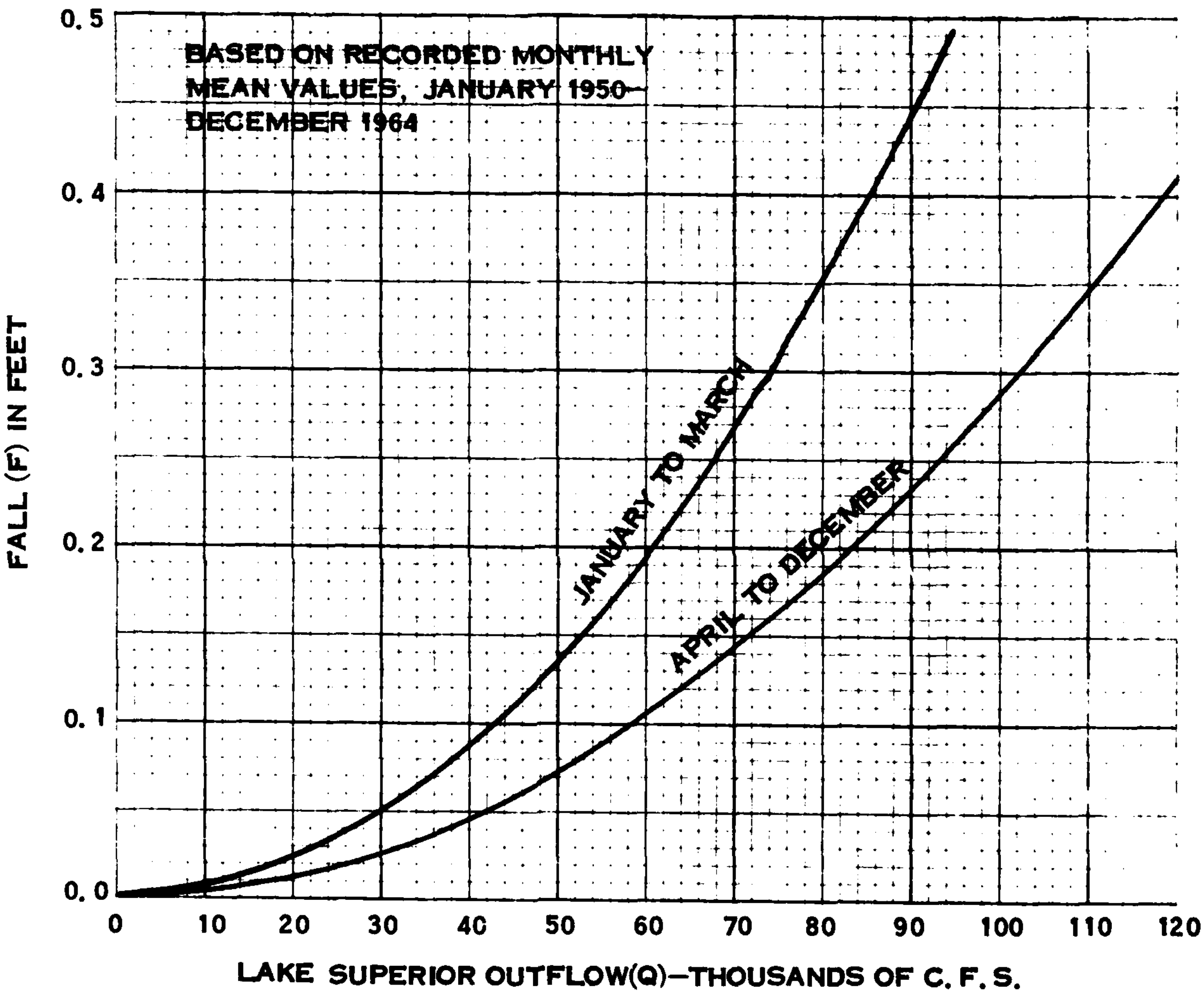
(4) Compute the permissible power diversions by the procedures outlined in Subsection 2.2.

(5) Determine total output from output-head-discharge curves. Details are given in the following subsections of the methods employed for computing total output and the derivation of various relationships.

2.3.1 Canadian Plant

Head Determination: The head available at the plant was determined as the difference in elevation between the two lakes less the loss from Lake Superior to the plant foreway and the loss from the plant tailwater to Lake Huron. The relationships employed were as follows:

(1) Head loss from Lake Superior to CHS Gauge 011: The head loss relationship was determined from monthly mean records of Lake Superior outflow and Lake Superior levels at Marquette, Michigan and CHS Gauge 011 available for the period 1950 through 1964. Two relationships were required; one for the ice cover period, January to March, and the other for the open water period, April to December. The curves are shown on Figure E-2 and their equations are:



ST. MARYS RIVER FALL FROM LAKE SUPERIOR AT MARQUETTE TO CHS GAUGE 011

FIGURE E–2

Jan - Mar $Q = 135115 \quad F^{1/2}$

$$\text{or EL011} = \text{Superior Level} - \frac{Q^2}{(135115)^2}$$

Apr - Dec $Q = 187070 \quad F^{1/2}$

$$\text{or EL011} = \text{Superior Level} - \frac{Q^2}{(187070)^2}$$

where F = fall or head loss in feet

= Superior Level - EL011 level, and

EL011 = Elevation at CHS Gauge 011 in feet

(2) Head loss from CHS Gauge 011 to Great Lakes Power Plant forebay:

A single relationship is applicable to all months and is shown on Figure E-3. The equation for forebay elevation was based on the expected performance of the redeveloped forebay canal as determined by Acres Consulting Service:

$$F_H = \text{EL011} - 0.0211 \times Q_c^{2.2826} (\text{EL011}-574.147)^{-6.06}$$

where F_H = forebay elevation (in feet),

EL011 = elevation at CHS Gauge 011 in feet, and

Q_c = Canadian Diversion in cfs.

(3) Head loss from Lake Huron to CHS Gauge 012 : Head losses were determined by unit fall relationships between levels at CHS Gauge 012 and Lake Huron at Harbor Beach, Michigan and Lake Superior outflow based on monthly mean records for the period 1950 to 1964. Two relationships were required one for the ice cover period January to March, and one for the open water period, April to December. These relationships are shown on Figure E-4 and Figure E-5. The equations are:

Jan to Mar:

$$\text{MWS} = 571.07+0.0001463\ Q_c F^{-1/2}$$

Apr to Dec:

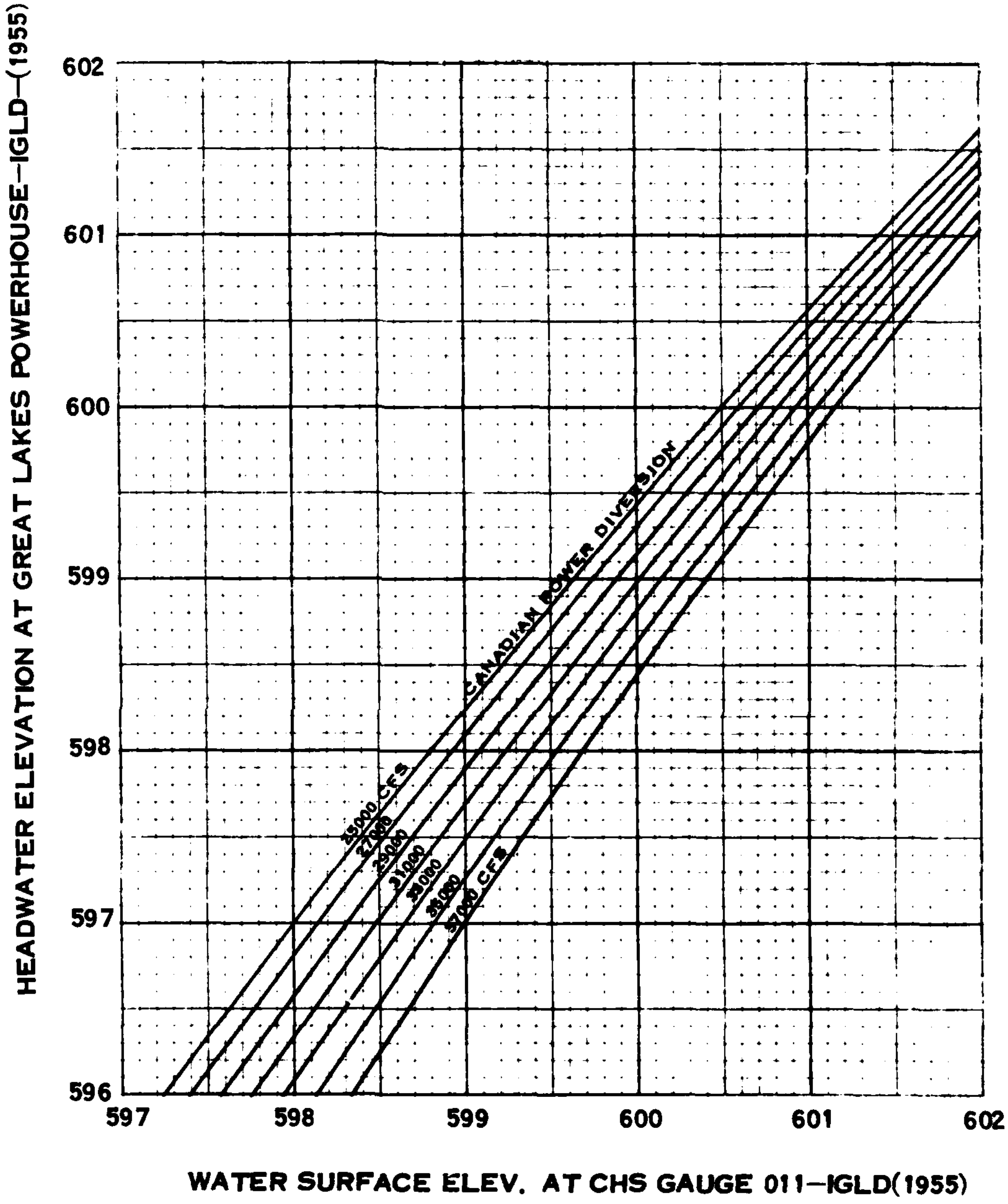
$$\text{MWS} = 569.10+0.0001489 \times Q_c F^{-1/2}$$

where F = head loss or fall in feet
= EL012 - Huron Level,

where EL012 = elevation at CHS Gauge 012, and

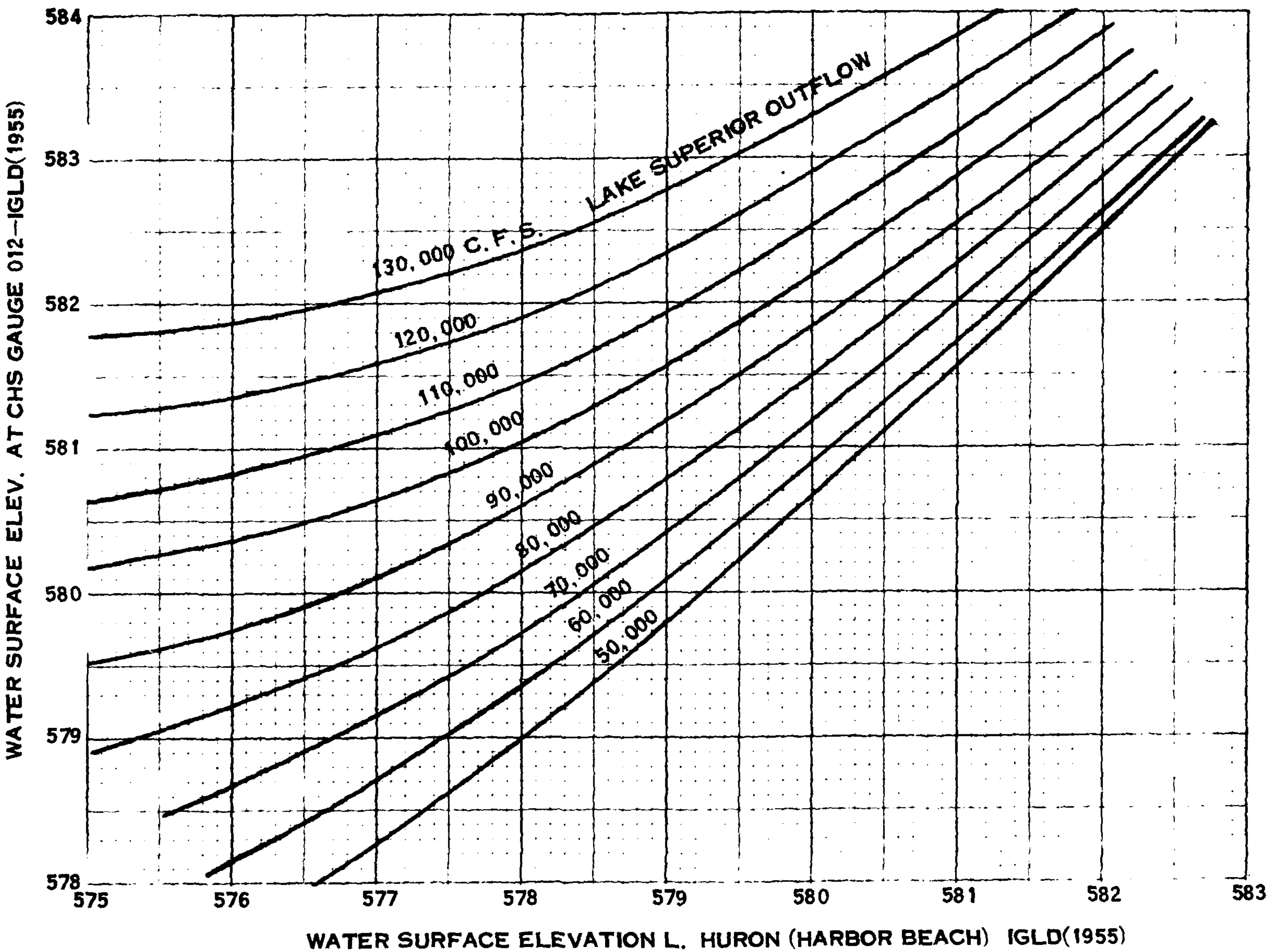
MWS = mean water surface elevation

$$= \frac{\text{Huron Level} + \text{EL012}}{2}$$



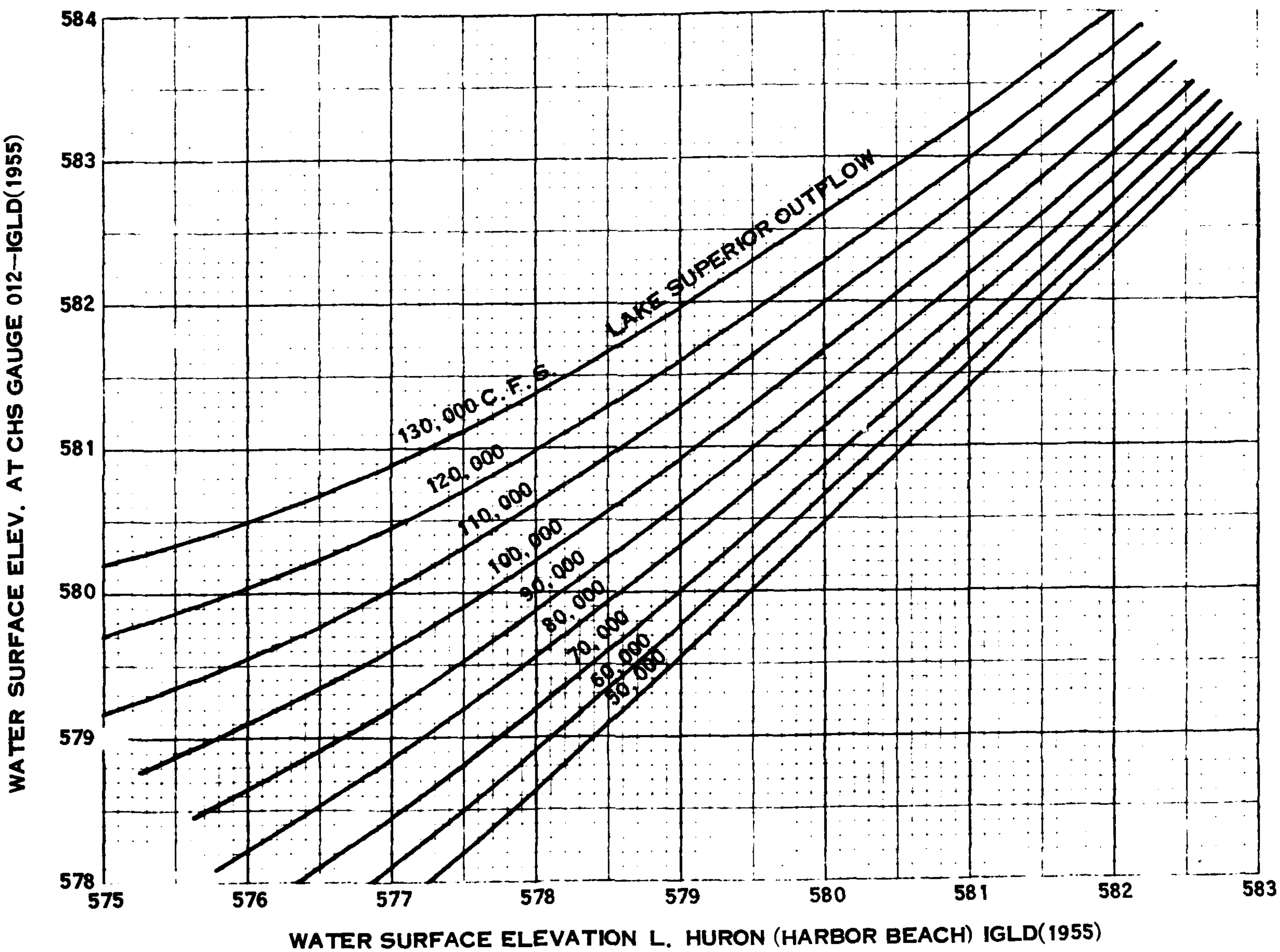
ST. MARYS RIVER BACKWATER SLOPES CHS GAUGE 011 TO GREAT LAKES POWERHOUSE FOREBAY FOR VARIOUS DIVERSIONS

FIGURE E–3



ST. MARYS RIVER BACKWATER SLOPES LAKE HURON TO CHS GAUGE 012 JAN. –MAR.

FIGURE E–4



ST. MARYS RIVER BACKWATER SLOPES LAKE HURON TO CHS GAUGE 012 APR.–DEC.

FIGURE E–5

Substitution of the above relationships gives the following equation for the two periods:

Jan to Mar:

$$EL012 = \text{Huron Level} + \frac{(0.0002926 \times Q_C)^2}{(\text{Huron Level} + EL012-1142.14)^2}$$

Apr to Dec:

$$EL012 = \text{Huron Level} + \frac{(0.0002978 \times Q_C)^2}{(\text{Huron Level} + EL012-1138.2)^2}$$

(4) Head loss from CHS Gauge 012 to GLP Tailrace: A single relationship is applicable to all months to determine tailwater elevation. This is shown in Figure E-6. The equation for tailwater elevation as determined by Acres Consulting Services is:

$$F_T = EL012 + 1.2394 \times 10^{-11} \times Q_C^2 \ (590.551-EL012)^{1.39}$$

where F_T = tailwater elevation in feet, and EL012 is determined from equations described above.

(5) Head is calculated as forebay level (F_H) minus tailwater level (F_T), each of which is defined above.

Plant Output Determination: The total plant output-discharge-head relationship shown on Figure E-7, for the new GLP plant was derived by Ontario Hydro from an expected performance curve supplied by Acres Consulting Service Ltd. This relationship was at a rated head of 19.69 feet and was expanded by Ontario Hydro to cover the head range from 16 to 22 feet. For combinations of head and Canadian Diversion Q_C below the best efficiency less 1 percent line, values of MW are computed from the following equation:

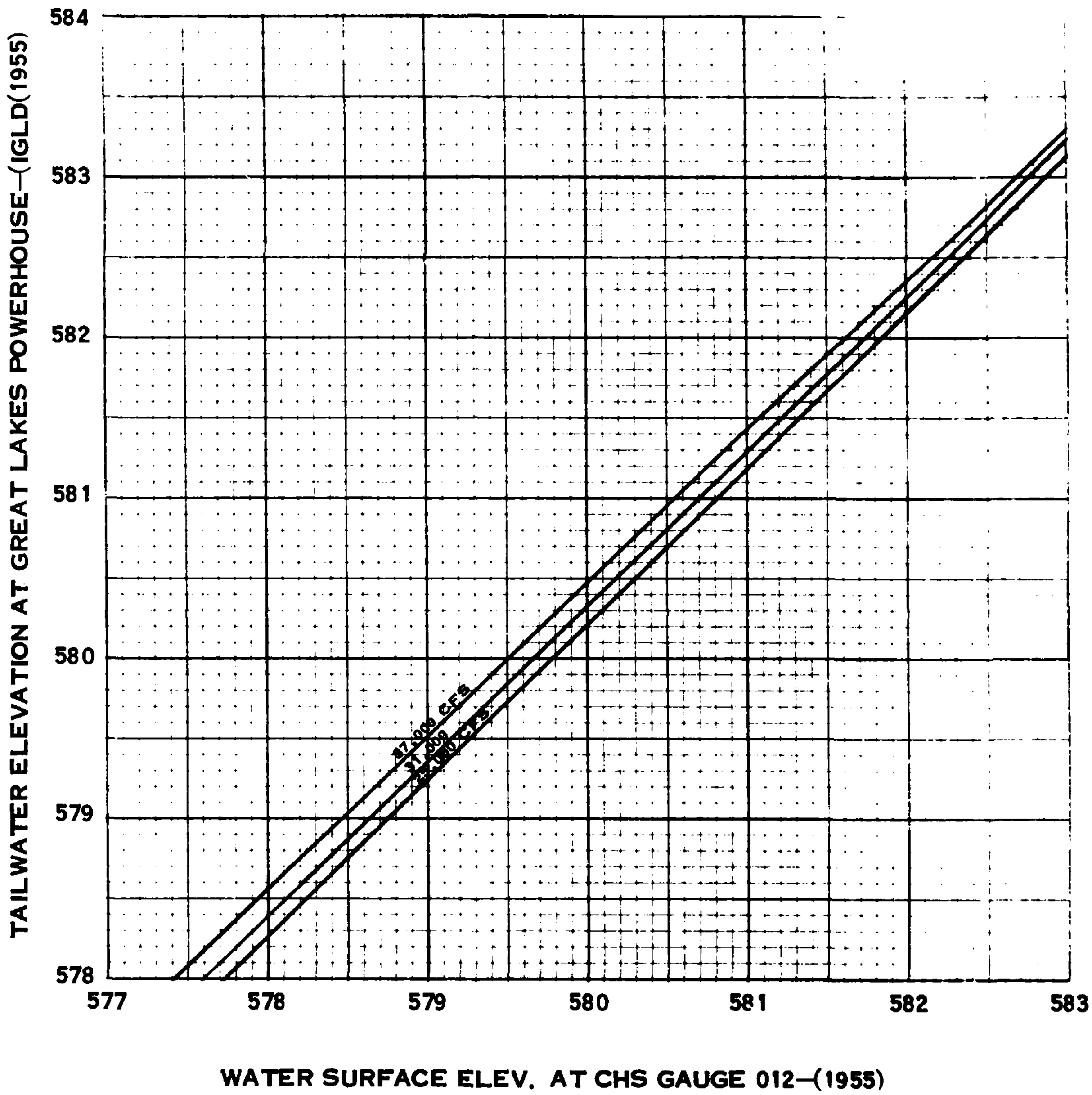
$$MW = 0.072691 \times Q_C \ H$$

where MW = power in megawatts,

H = head in feet, and

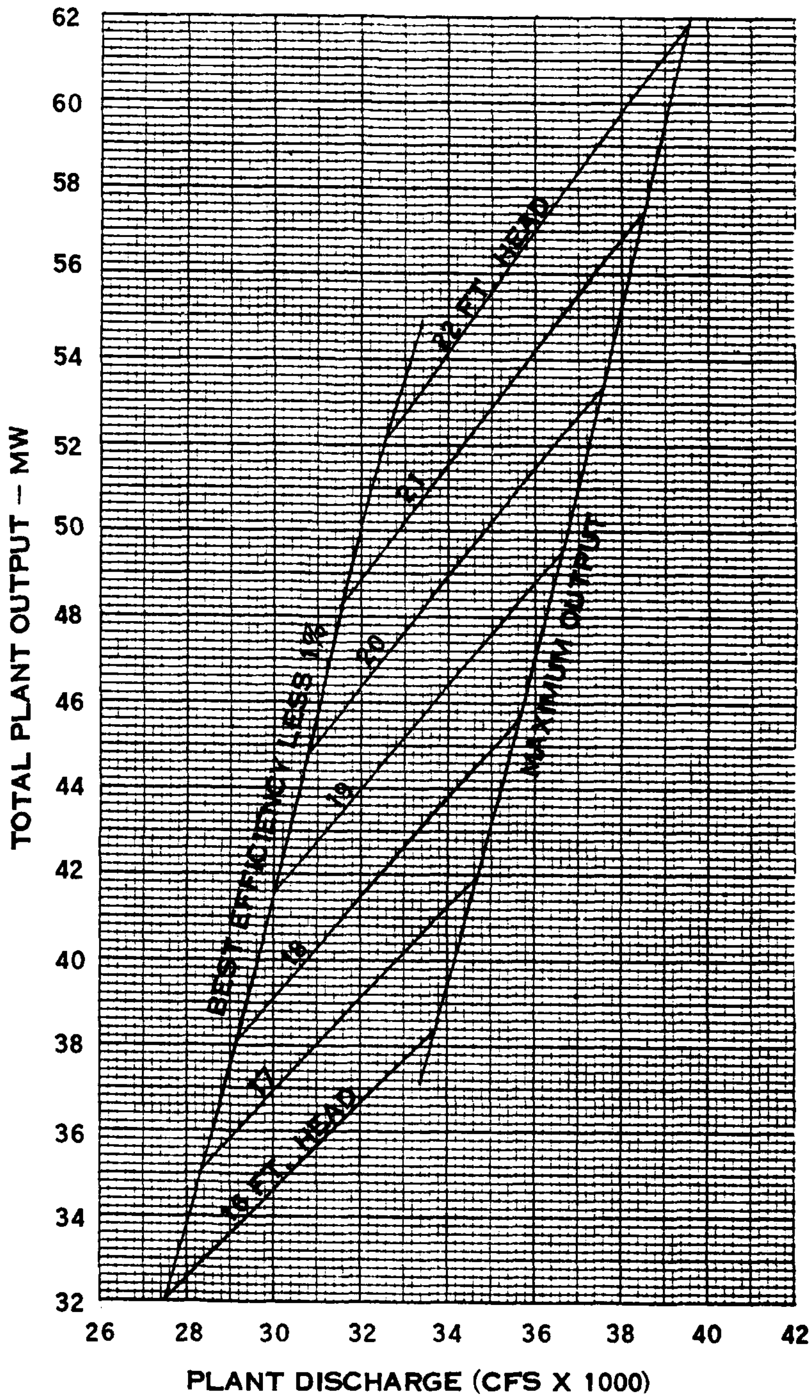
0.072691 = economy factor per foot of head. (from best efficiency less 1 percent line)

For values of head and Q_C between the best efficiency less 1 percent line and the maximum output line Figure E-7 is used to determine power. For values of head and Q_C greater than the maximum output line, a



ST MARYS RIVER GAUGE RELATIONSHIP BETWEEN CHS GAUGE 012 AND GREAT LAKES POWERHOUSE TAILWATER

FIGURE E—6



ST. MARYS RIVER GREAT LAKES POWER CORPORATION
PLANT OUTPUT–DISCHARGE RELATIONSHIP
FOR RANGE OF GROSS HEADS

FIGURE E–7

useable value of discharge Q_a is determined by incrementally reducing Q_c and recalculating head until Q_c and head intersect on the maximum output line in Figure E-7.

2.3.2 United States Plants

Head Determination: The head available at each plant was determined as the difference in elevation between the two lakes, less the loss from Lake Superior to the plant forebay, and the loss from the plant tailwater to Lake Huron. The relationships employed were as follows:

(1) Head loss from Lake Superior to Southwest Pier Gauge, located in the proximity of the entrance to the Edison Sault Electric Company Power Canal:

$$\text{Head Loss} = 0.0037143\ Q_o \times 10^{-3} - 0.06572$$

where Q_o = Lake Superior monthly mean outflow in cfs.

(2) Head loss from U.S. Slip Gauge (USS), located near the tailrace for the Edison Sault plant, to Lake Huron:

Open Water:

$$\text{Head Loss} = (Q/1.605)^{2.5}/(\text{USS}-567.29)^{3.75} + 0.09$$

Ice Period:

$$\text{Head Loss} = (Q/1.93)^{5}/(\text{USS}-569.56)^{7.5} + 0.09$$

(3) Head loss, in feet, in the Edison Sault Power Canal is computed as follows: (Note: The maximum allowable head loss is limited to 3.5 feet by the power company to keep excessive velocities from damaging the canal walls)

$$\text{Head loss} = 27.800\ Q_s^{2.6}/(\text{SWP}-568.97)^{5.2}$$

where: Q_s = canal flow in 1000 cfs,
SWP = water surface elevation at the Southwest Pier Gauge in feet.

(4) The Edison Sault Plant tailrace elevation is assumed to be lower than the water surface elevation at USS by a constant 0.2 feet.

(5) For the U.S. Government plant, the head loss consists of the river loss from Southwest Pier gauge to the regulating works, the loss in the head race to the plant forebay, and the loss from the tailrace to U.S. Slip gauge. The discharge through the Government plant is practically constant at about 12,700 cfs and accordingly there is no variation of head loss in the headrace or tailrace due to discharge. There is a small variation in head loss in the tailrace which is related to the river stage below the rapids. No accurate relationships between

the river losses and the river flows have been established but they are very small in magnitude compared to the overall head. The variations in these small losses have insignificant effect on the evaluation of the various regulation plans. For the purposes of the present evaluations, the head loss between SWP and USS were assumed constant at 0.6 feet.

Plant Output Determination: The plant output equations for each of the United States plants are as follows:

(a) Power output by U.S. Government plant:

$$P = 1055\,H - 2890$$

for values of H of 21.5 or less

$$P = 4280\,H - 75H^2 - 37{,}560$$

for values of H of 21.5 or more

where P is a power output in kW for an assumed constant plant water use of 12,700 cfs and H is the net head on the plant in feet.

(b) Power output by Edison Sault plant

$$P_a = 0.701\,(82H - 220 + (89.5H - 39)Q)$$

when Q is less than 18.16 + 0.59H

$$P_b = P_a - 103\,(Q - 18.16 - 0.59H)^{1.6}$$

when Q exceeds 18.16 + 0.59H

$$P_c = P_b - 70.1\,(Q - 20.16 - 0.59H)^{1.6}$$

when Q exceeds 20.16 + 0.59H and H exceeds 17

Where P_a, P_b, and P_c = power outputs in kW,
Q = plant water use in 1000 cfs, and
H = net head on the plants in feet.

Section 3

NIAGARA RIVER POWER PLANTS

3.1 General Description

The outflow from Lake Erie which is utilized for power is diverted to the various hydroelectric plants by means of the Welland Canal and by several structures from the Niagara River at the Chippawa-Grass Island Pool about a mile above Niagara Falls. Plants in Canada are served from both sources, whereas in the United States diversion is totally from the Niagara River at the Chippawa-Grass Island Pool. Figure E-8 is a general location plan of the Niagara River and Figure E-9 shows the detail location of diversion structures and hydroelectric power plants at Niagara Falls.

3.1.1 Canadian Plants

There are seven hydroelectric power plants on the Canadian side of the Niagara River which take water either directly from the river or from Lake Erie via the Welland Ship Canal. Table E-1 lists the plants, the source of water supply, number of units, rated head and installed capacity.

Table E-1

Hydroelectric Plants In Canada Using Outflow From Lake Erie

Plant	Source of Water Supply	No. of Units	Rated Head (feet)	Installed Capacity (kW)
DeCew Falls No. 1	Welland Canal	6	266	31,900
DeCew Falls No. 2	Welland Canal	2	283	115,200
Sir Adam Beck No. 1	Niagara River	10	291-301	414,650
Sir Adam Beck No. 2	Niagara River	16	291-301	1,223,600
Pumping Station	Niagara River	6	60-85	
and Generating Station	Niagara River	6	50-75	176,700
Ontario Power	Niagara River	12	205	101,460
Canadian Niagara Power Co. (Rankine)	Niagara River	11	126	94,680

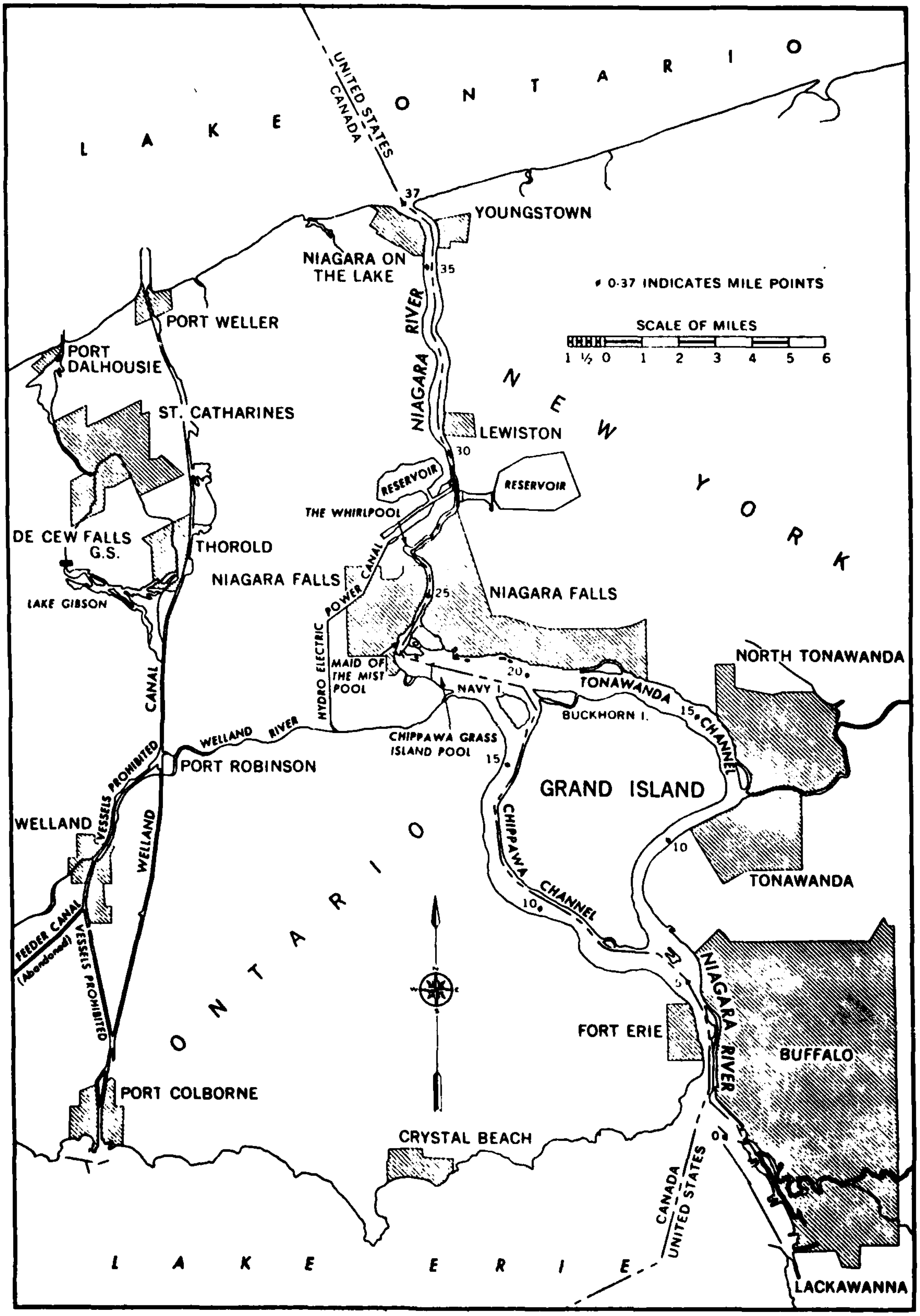


FIGURE E–8
PLAN OF NIAGARA RIVER–LAKE ERIE TO LAKE ONTARIO

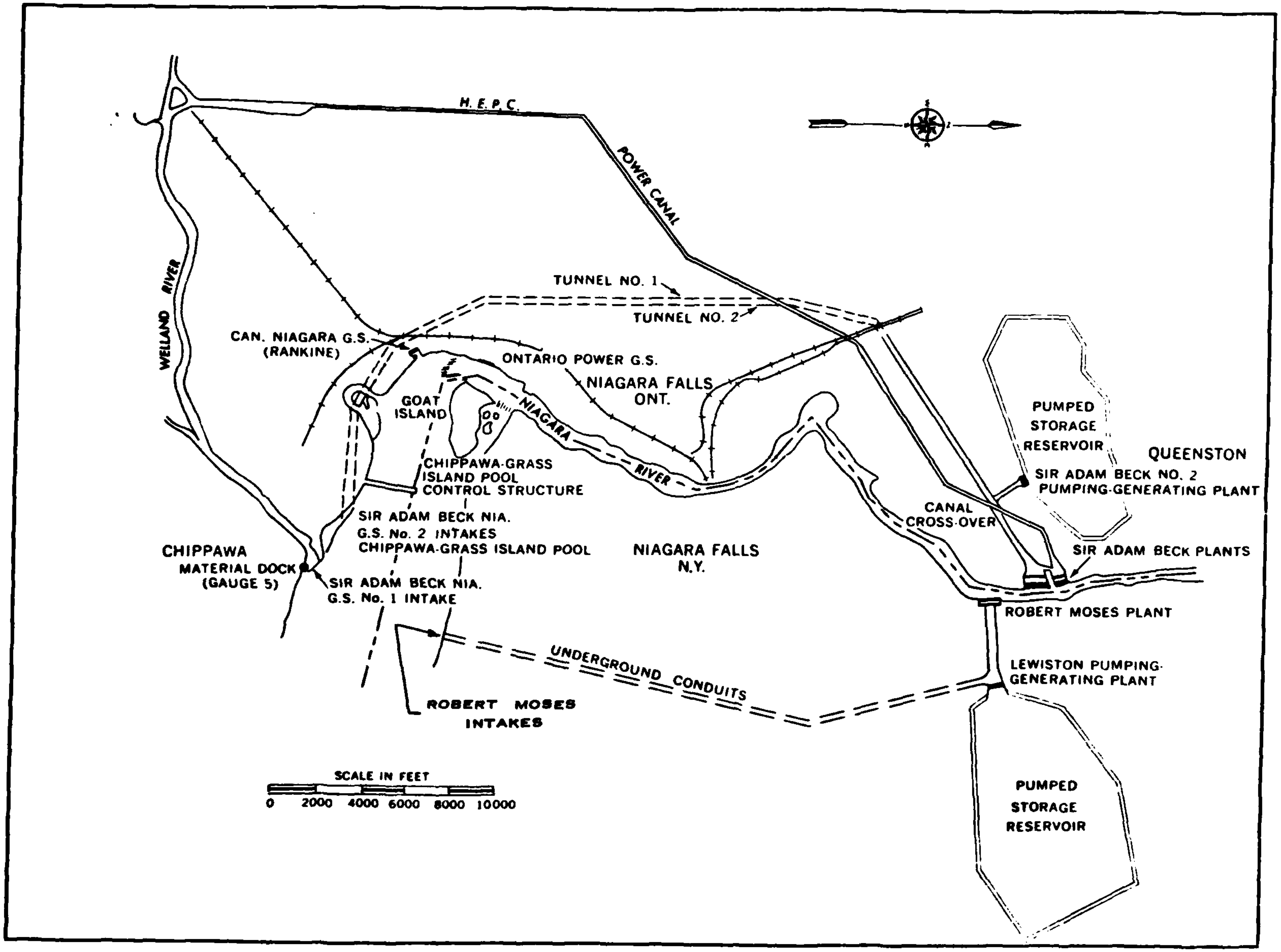


FIGURE E-9

NIAGARA RIVER—DETAIL LOCATION OF HYDROELECTRIC POWER PLANTS AND DIVERSION WORKS

3.1.2 United States Plants

The existing United States hydroelectric plants are the Robert Moses Niagara Power Plant and the Lewiston Pumping-Generating Plant. These plants have 13 and 12 units, respectively, with rated heads of 300 and 85 feet. Installed capacities of these plants are 1950 megawatts and 240 megawatts respectively. Both plants are owned and operated by the Power Authority of the State of New York.

3.2 Methodology for Determining Energy and Peak Capacity Output

This section presents the assumptions and methods developed by Ontario Hydro and the Power Authority of the State of New York for computing energy and peak capacity outputs obtainable from Canadian and United States hydroelectric power plants in the Niagara area. These methods are used to compute the outputs which would be available from existing facilities with basis-of-comparison Lake Erie levels and outflows and Lake Ontario levels, and the outputs which would be available from these same facilities with levels and outflows which result from the various regulation plans.

3.2.1 Assumptions

(1) For any Lake Erie outflow the diversion entitlements for Canada and the United States would be determined from the equations given in Subsection 3.2.3(3).

(2) The order of priority for Canadian plants diversion usage is as follows: DeCew, Sir Adam Beck (SAB) Nos. 1 and 2 ,and the pumping-generating station (PGS), Ontario Power (OP) and Canadian Niagara Power (CNP).

(3) The Niagara Falls flow requirements as set forth in the International Niagara Treaty of 1950 would be complied with; that is, flows of not less than 100,000 cfs over the Falls between the hours of 8:00 am and 10:00 pm from April 1 through September 15 and between the hours of 8:00 am and 8:00 pm from September 16 through October 31, (EST or EDT whichever is in effect in either country at Niagara Falls). The minimum flow over the Falls at any other time would be 50,000 cfs.

(4) In addition to the Falls flow requirements set forth above, an additional 600 cfs cushion will be provided at all times as per present operating practice. Cushion flow is excess flow dispatched to the Falls to ensure that the minimum Falls flow, requirements are complied with.

(5) The operating hours for the three alternative control structures, (25N, 15S, and 6L) would be those shown in Table E-2 (as recommended by the Regulatory Works Subcommittee). The operating hours for the Black Rock Canal schemes are constrained by commercial navigation, recreational boating, and lock maintenance.

(6) The elevation of the Chippawa-Grass Island pool would be operated within certain tolerances to maintain the long-term mean elevation of 561.0 IGLD as directed by the International Niagara Board of Control by letter to the Power Entities dated February 27, 1973.

Table E-2

Lake Erie Regulation Schemes - Operating Hours

Regulation Scheme	Month	Operating Hours
Niagara River Structure		
Plan 25N	All months	24
Black Rock Canal		
Plan 15S	Mid Apr - May	20:00 - 8:00
	June - August	24:00 - 8:00
	Sept - Mid Dec	20:00 - 8:00
	Mid Dec - Mid Apr	24
Plan 6L	Mid Apr - Mid Mar	Same as 'S'
	Mid Mar - Mid Apr	0

3.2.2 Basic Data

Except as noted below, the basic data used in these computations were developed by the Regulation Subcommittee and are given in Appendix A - Lake Regulation, Volume 2. Coordinated Basic Data.

(1) Mean monthly basis-of-comparison Lake Erie outflows and levels and corresponding Lake Ontario levels resulting from Plan 1958-D with discretionary deviations (1900-1976).

(2) Mean monthly Lake Erie outflows and levels resulting from Plans 25N, 15S, 6L and corresponding Lake Ontario levels resulting from Categories 1, 2 and 3 regulation alternatives as described in Section 1.3.

(3) Niagara River monthly mean local inflows, given in the report on Lake Erie Outflows 1860 to 1964, dated June 1965, by the Coordinating Committee on Great Lakes Basic Hydraulic and Hydrologic Data.

(4) Head losses and diversion capabilities for the water supply tunnels and canals as determined by actual field tests.

(5) Diversion capabilities, and power output - flow relationships for each generating station as determined from field tests augmented by operating experience.

3.2.3 Derived Data

Depending on the regulation plan being evaluated, adjustments were made to the data as follows:

(1) Within the day variation of Lake Erie Outflow: Under regulation Plans 15S and 6L, Lake Erie outflow would be increased by 15,300 and 6,800 cfs, respectively, during the daily operating hours listed in Table E-2 for those months when the supply to the upper Lakes is above normal. For regulation purposes, each increase was computed as a 24 hour daily mean and applied on a monthly basis. To evaluate the effect of the flow increase on power production, it was necessary to determine from the monthly mean Lake Erie outflow, the daytime and nighttime values coinciding with the daily operating hours of the regulation structure and to adjust them to reflect the Treaty hours since these do not exactly correspond to the hours defined in Table E-2. In order to make the necessary adjustments, a base outflow was determined from the following equation:

Lake Erie Base Flow (1,000 cfs)
$= 3.665\ (\text{Lake Erie level} - 556.25)^{1.5} - \text{R1N(K)} + 7$

where: R1N(K) is the ice and weed retardation for the Niagara River for the month K, and the figure "7" refers to Welland Canal flow (7,000 cfs).

The values of R1N for any month K are as follows:

Month	R1N	Month	R1N
January	4.0	July	5.1
February	4.7	August	3.9
March	3.4	September	2.6
April	4.9	October	1.6
May	0.0	November	0.4
June	1.5	December	0.0

By inputting any particular monthly mean Lake Erie level into the above equation, the Lake Erie base flow before adjustment can be determined. If the base flow equals the flow given by the data set, then the trigger is not operating, and no further adjustment is made. If the base flow is less than the given flow, then the trigger is operating and the base flow is increased by values adjusted for daytime and nighttime, which are calculated to reflect the Treaty hours of operation and the 15,300 cfs or 6,800 cfs increase called for by plan 15S or 6L respectively. The following equation was used to adjust the Lake Erie Base Flow when the trigger was operating:

Lake Erie Outflow (treaty hours) = Base Flow + Q increase (K)

where Q increase for month K is shown in Table E-3.

Table E-3

Within The Day Variation Of Lake Erie Outflow

Month		Increase (cfs)		Month		Increase (cfs)	
		15S	6L			15S	6L
Jan	D	15300	6800	July	D	0	0
	N	15300	6800		N	12240	5440
Feb	D	15300	6800	Aug	D	0	0
	N	15300	6800		N	12240	5440
Mar	D	15300	3400	Sept	D	0	0
	N	15300	3400		N	16690	7418
Apr	D	7650	0	Oct	D	0	0
	N	16830	4080		N	15300	6800
May	D	0	0	Nov	D	0	0
	N	18360	8160		N	22950	10200
June	D	0	0	Dec	D	7650	3400
	N	12240	5440		N	19125	8500

(2) Lake Erie outflow available for power and Falls flow: Lake Erie outflows available for power and Falls flow were derived by subtracting from Lake Erie Base Flow, the Welland Ship Canal and New York State Barge Canal 1985 navigation requirements, adjusting for the effect of the Welland Ship Canal flow variations on the Niagara River flow and adding Niagara River local inflow. These adjustments are summarized in Table E-4.

Table E-4

Adjustment To Lake Erie Outflow

	Welland Ship Canal	NY State Barge Canal	Effect of WSC Variation	Niagara River Local Inflow	Net Adjustment
Jan	0	0	+ 1,800	1,300	3,100
Feb	0	0	+ 1,500	1,300	2,800
Mar	500	0	+ 800	3,200	3,500
Apr	2,100	700	- 800	3,300	- 300
May	3,300	1,100	- 1,300	1,600	- 4,100
June	3,200	1,100	- 1,000	800	- 4,500
July	3,100	1,100	- 700	500	- 4,400
Aug	3,100	1,100	- 600	300	- 4,500
Sept	3,000	1,100	- 400	300	- 4,200
Oct	3,100	1,100	- 400	500	- 4,100
Nov	3,000	1,100	- 200	900	- 3,400
Dec	900	300	+ 1,300	1,100	+ 1,200

The sources of adjustments in Table E-4 are as follows:

(a) The monthly and half-monthly Welland Ship Canal (WSC) and New York State Barge Canal Flows for the projected 1985 navigation requirements.

(b) Adjustments for the effect on Niagara River flows of monthly variations in Welland Canal navigation flows, developed by Ontario Hydro.

(c) The Niagara River monthly mean local inflows, given in the Coordinating Committee Report on Lake Erie Outflows, 1860-1964.

(3) The diversion entitlements for Canada and the United States for power generation for any Lake Erie outflow are based on Article III, Niagara Diversion Treaty, 1950.

Canadian entitlement = 1/2 (adjusted Lake Erie outflow - Falls flow + 5,000)

U.S. entitlement = 1/2 (adjusted Lake Erie outflow - Falls flow - 5,000)

(4) Daytime and nighttime diversion variation due to tourist season ponding:

Adjustment is made to the daytime and nighttime Canadian flow diversion due to the effect of ponding water in the Chippawa-Grass Island Pool

during the tourist season for use at the SAB plants during daytime hours. A maximum 75,000 cfs hours may be stored at night and released during the daytime. Only water available to the OP and CNP plants is used for ponding. Based upon the average tourist season nighttime Treaty hours of 10.43 hours, the maximum nighttime ponding into Grass Island Pool is 7,190 cfs. Either the flow available to OP or the maximum nighttime ponding figure, whichever is less, is subtracted from the total nighttime Canadian power diversion to account for ponding. The resulting additional flow for power to be added to the total Canadian daytime power diversion is given by the following formula:

$$\text{Daytime Ponding Release} = \text{Nighttime Ponding (cfs)} \times \frac{10.43}{13.57}$$

This gives a maximum release of 5,526 cfs.

3.2.4 Energy Output Computations for Canadian Plants

The energy outputs obtainable from the Canadian power plants during daytime and nighttime hours were computed monthly over the period January 1900 to December 1976, for the basis-of-comparison and for each regulation plan. Daytime energy is considered to be that generated between 7:00 am and 11:00 pm and nighttime energy, that generated between 11:00 pm and 7:00 am. The method of computing these daytime and nighttime energy outputs for each month of the 77-year period is described in the following paragraphs.

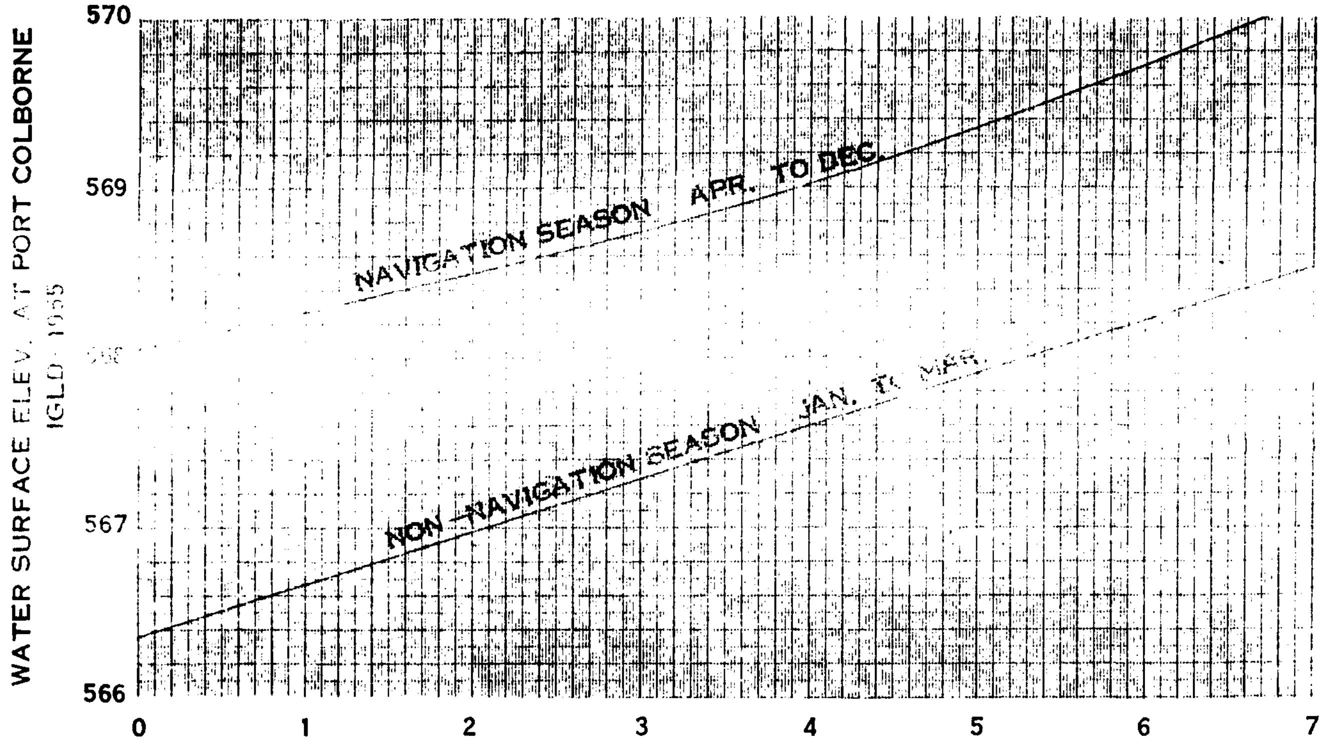
(1) From the Canadian flow entitlement computed in Subsection 3.2.3(3), the diversion flow to each generating station was computed for two periods, tourist season day (100,600 cfs Falls flow) and tourist season night (50,600 cfs Falls flow) for the tourist season months, April through October, and for one period non-tourist season (50,600 cfs Falls flow) for the non-tourist season months, November to March.

(2) The energy output at each generating station was computed as the product of the diversion flow and the economy factor (kW/cfs).

(3) The order of priority of the plants is as described in Subsection 3.2.1(2).

(4) The diversion to the DeCew plants was computed to be the lesser between 7,000 cfs minus the WSC navigation requirement shown in column 1 of Table E-4, or as determined from the graph in Figure E-10 which shows the limiting DeCew diversion on Lake Erie level. This limiting condition occurs only during periods of extreme low Lake Erie levels. The maximum diversion to DeCew is 6,800 cfs. The average energy output from the DeCew plants was computed as 20.37 kW for each cfs diverted.

(5) The diversion to the SAB plants was considered to be the flow available to Canada minus the DeCew diversion or the maximum diverting capacity of the Beck tunnels and canals at a forebay level of 540.0 and Chippawa-Grass Island Pool level of 561.0, whichever is less.



DECEW FALLS DIVERSION—THOUSANDS OF C. F. S.

BASED ON OBSERVED DAILY MEANS – NAVIGATION SEASON, OCT. 1962 TO DEC. 1963

NON-NAVIGATION SEASON, JAN. 1963 TO MAR. 1964 AND DEC. 9 TO DEC. 27 1964

RELATIONSHIP BETWEEN LAKE ERIE ELEVATION AT PORT COLBORNE AND DIVERSION AVAILABLE TO DECEW FALLS G. S.

FIGURE E–10

(6) The diversion capacity which varies with the season due to equatic weed retardation, is determined from one of the three unit-fall relationships shown on Figure E-11.

(7) If the water available is less than the full diverting capacity, then the forebay elevation will be greater than 540.0 and is computed by an iterative procedure from the unit-fall relationships.

(8) The SAB tailwater level was computed for each month from the graphs on Figure E-12 showing the relationship between SAB tailwater level, Lake Ontario level, and Niagara River flow at Queenston.

(9) The gross head is computed as the difference between the headwater level computed as described in (7) and the tailwater level computed as described in (8).

(10) The average energy output from the SAB plants 1 and 2 was computed from the diversion flow described in (5) and (6), and the economy factor (kW/cfs) based on the head computed in (9).

$$\text{EF at head (H)} = \frac{\text{head (H)}}{291} \times 22.0 \text{ kW/cfs}$$

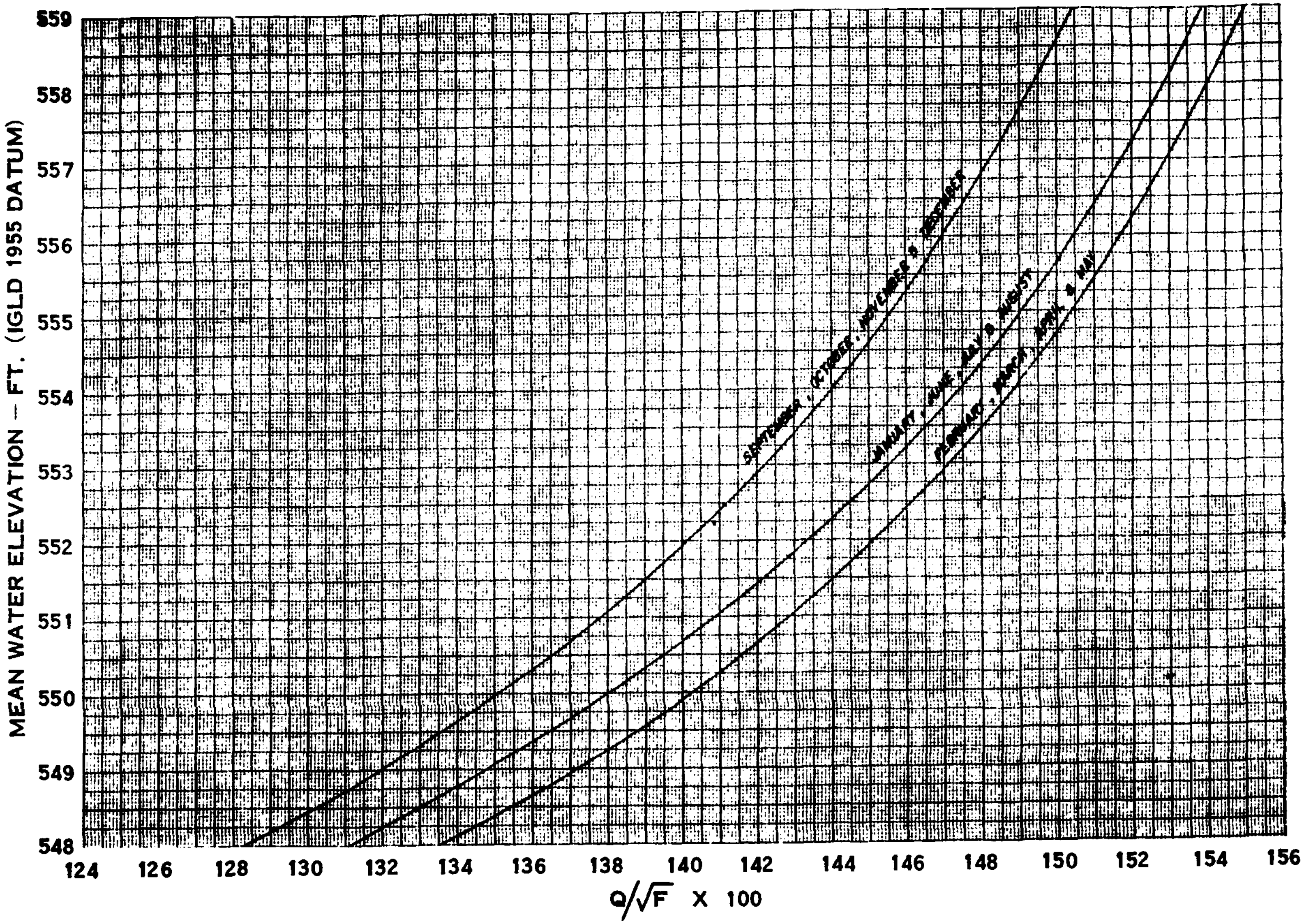
(11) The diversion available to the OP plant is the Canadian entitlement less DeCew, and the SAB plants, up to a capacity of 8,300 cfs. Output from the OP plant is computed from the available diversion at 12.6 kW/cfs.

(12) The remaining flow available to Canada after loading the OP plant is used at the CNP plant to a maximum capacity of 9,900 cfs. Based on operating experience, during tourist nights and the non-tourist season (50,600 cfs over the Falls) 1 cfs is diverted to CNP for every 2 cfs available. During the ice cover months of January, February and March, the maximum usable flow at CNP is assumed to be 1,000 cfs. The power at CNP is computed from the diverted flow at 7.6 kW/cfs.

(13) Total energy output (treaty hours) from the Niagara River plants in average MW is the sum of the individual outputs computed in (4), (10), (11) and (12) for tourist season days (TSD), tourist season nights (TSN) and the non-tourist season (NTS).

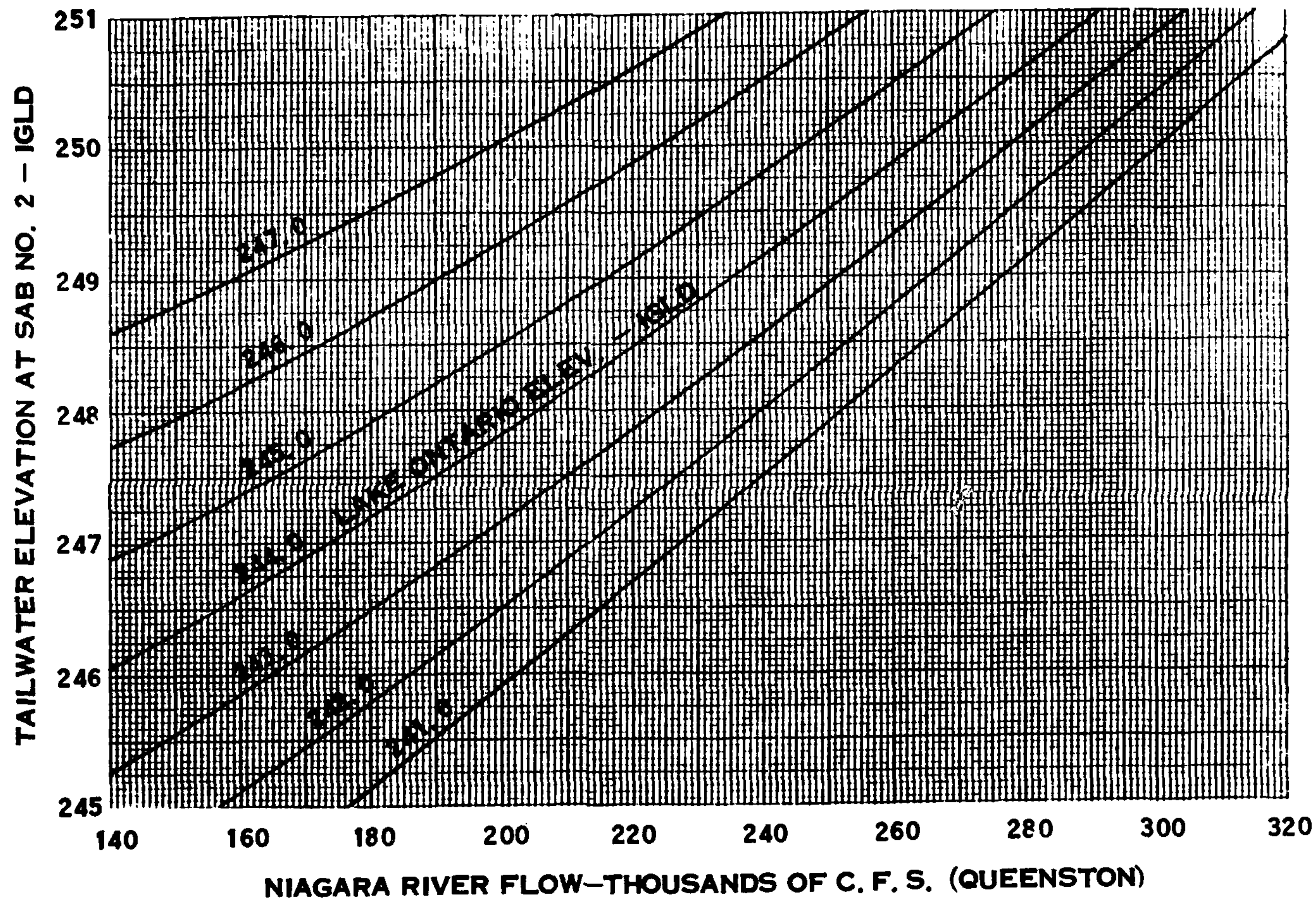
(14) Total daily energy output (operating hours) in MW hours is computed as follows:

daytime energy	Apr to Aug	= TSD x 14 hrs + TSN x 2 hrs
	Sept	= TSD x 13 hrs + TSN x 3 hrs
	Oct	= TSD x 12 hrs + TSN x 4 hrs
	Nov to Mar	= NTS x 16 hrs
nighttime energy	Apr to Oct	= TSN x 8 hrs
	Nov to Mar	= NTS x 8 hrs



SAB – NIAGARA G.S. NO. 1 AND 2 UNIT FALL – DISCHARGE RELATIONSHIP
MATERIAL DOCK (GAUGE 5) TO CANAL CROSSOVER GAUGE
TWO TUNNELS AND POWER CANAL

FIGURE E – 11



RELATIONSHIP BETWEEN NIAGARA RIVER FLOW LAKE ONTARIO ELEVATION AND SAB NO. 2 TAILWATER ELEVATION

FIGURE E–12

(15) An adjustment for PGS operation was made which resulted in a gain in total daytime energy and loss in total nighttime energy. These gains and losses, related to Niagara River flow, are shown on Figure E-13. It is assumed that the PGS storage reservoir is filled each night and the water fully utilized during the following day.

(16) Monthly energy in MW hours is computed as the daily energy from (15) x the number of days in each month.

3.2.5 Peak Output Computations for Canadian Plants

The peak output from the Canadian plants is related to the monthly mean daytime diversion. These relationships for the DeCew, SAB 1 and 2, and PGS, OP, and CNP plants are shown on Figures E-14, 15, 16 and 17.

3.2.6 Energy Output Computations for United States Plants

The effect on energy production resulting from a regulation plan are derived by comparing the total energy output of a base condition with the total energy obtainable from a specific regulation plan. Interest is focused on the change in value of energy accompanying a regulation plan rather than upon the absolute value of the total output.

The replacement cost of energy for each of the regulation plans is based on the New York Power Pool (NYPP) actual decremental costs experienced during intersystem energy transactions and is essentially the replacement cost of energy derived from oil fired units in the NYPP.

(1) For each calendar month, the total energy outputs in average MW are examined.

(2) The U.S. entitlement is determined in accordance with the Niagara Treaty and Chippawa-Grass Island Pool directives.

(3) The waterways head loss between Chippawa-Grass Island Pool and the forebay canal is computed from the relationship:

$$H_f = Q^2/K$$

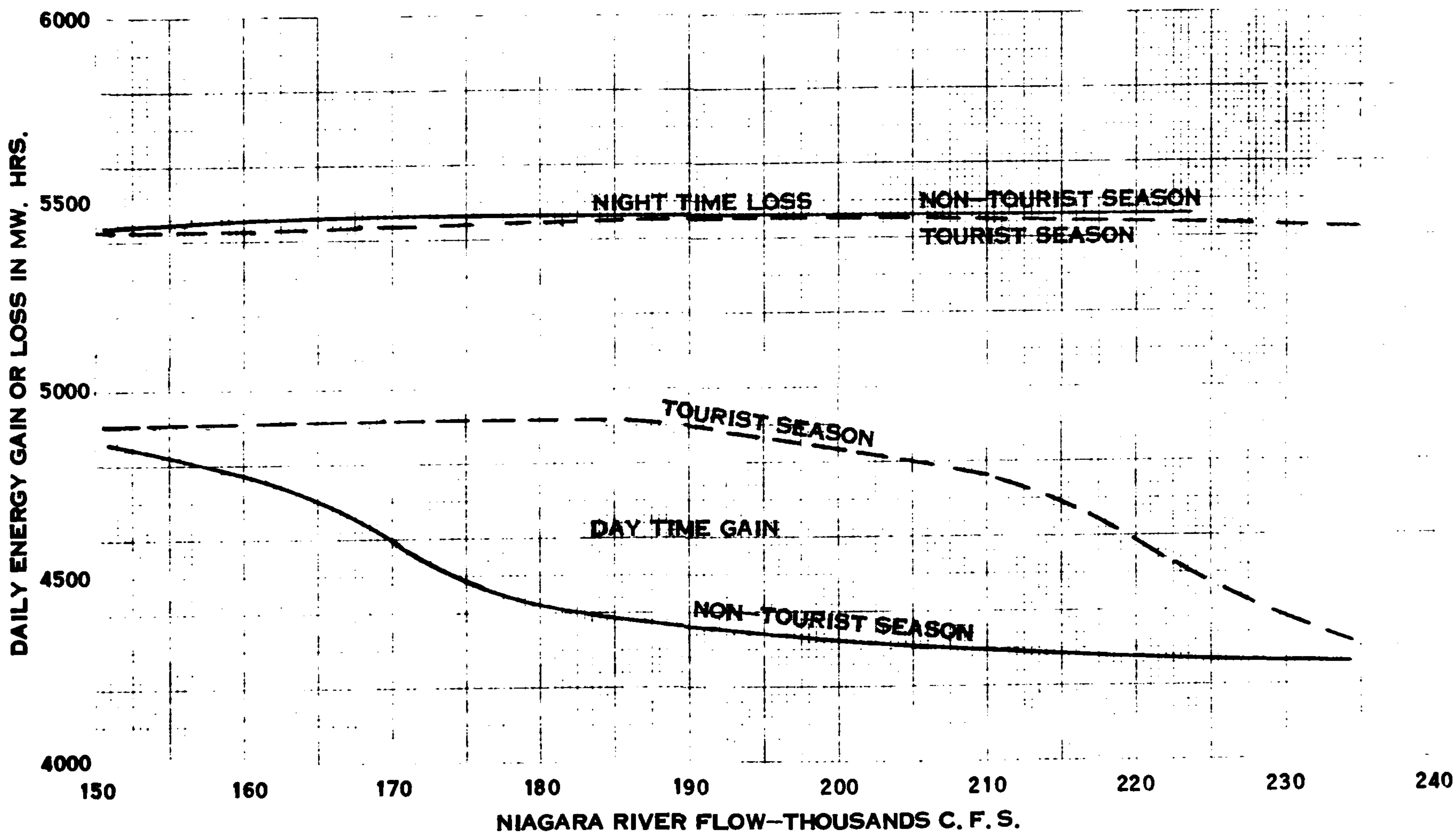
Where H_f = friction head loss in feet,

Q = PASNY diversion rate expressed in thousands of cfs, and

K = waterways roughness factor which varies month by month as indicated by several years of hourly operating measurements.

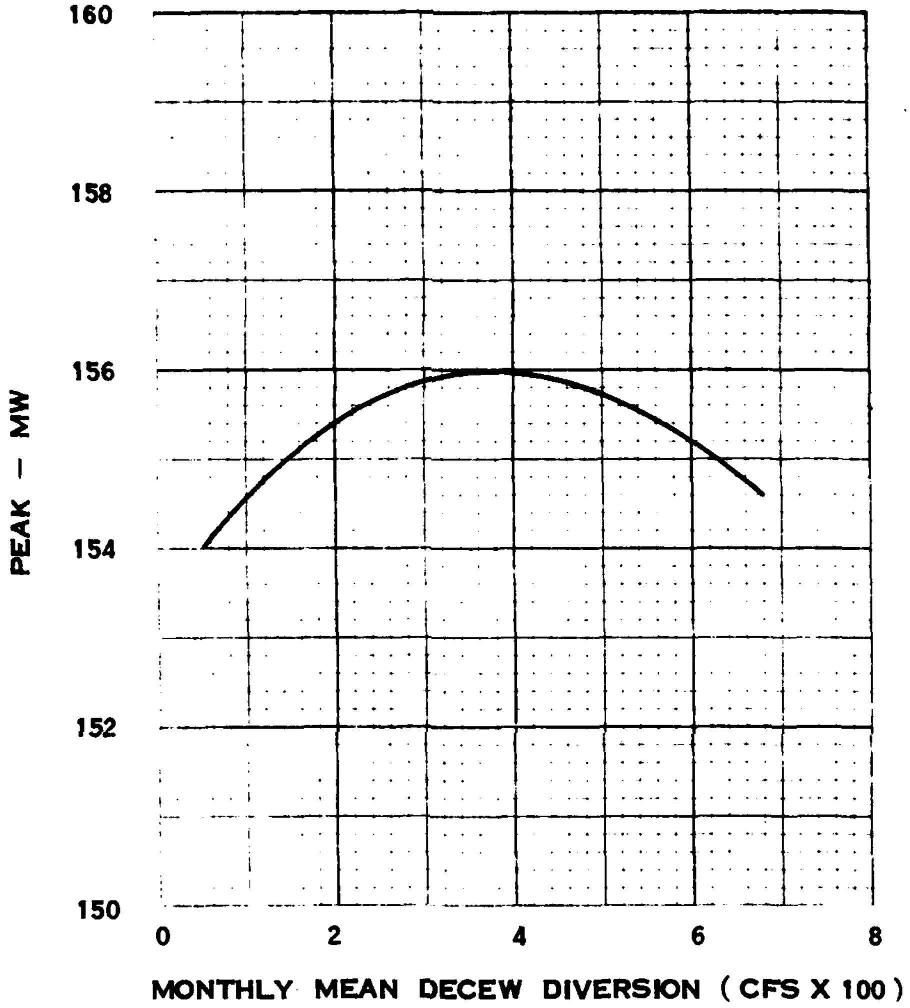
(4) The canal forebay level is computed as the Chippawa-Grass Island Pool level less waterways head loss.

(5) A Moses plant tailrace elevation of 250.0 is assumed. This provides a gross head on the Moses plant equal to the difference between the forebay level described in item (4) and 250.0.



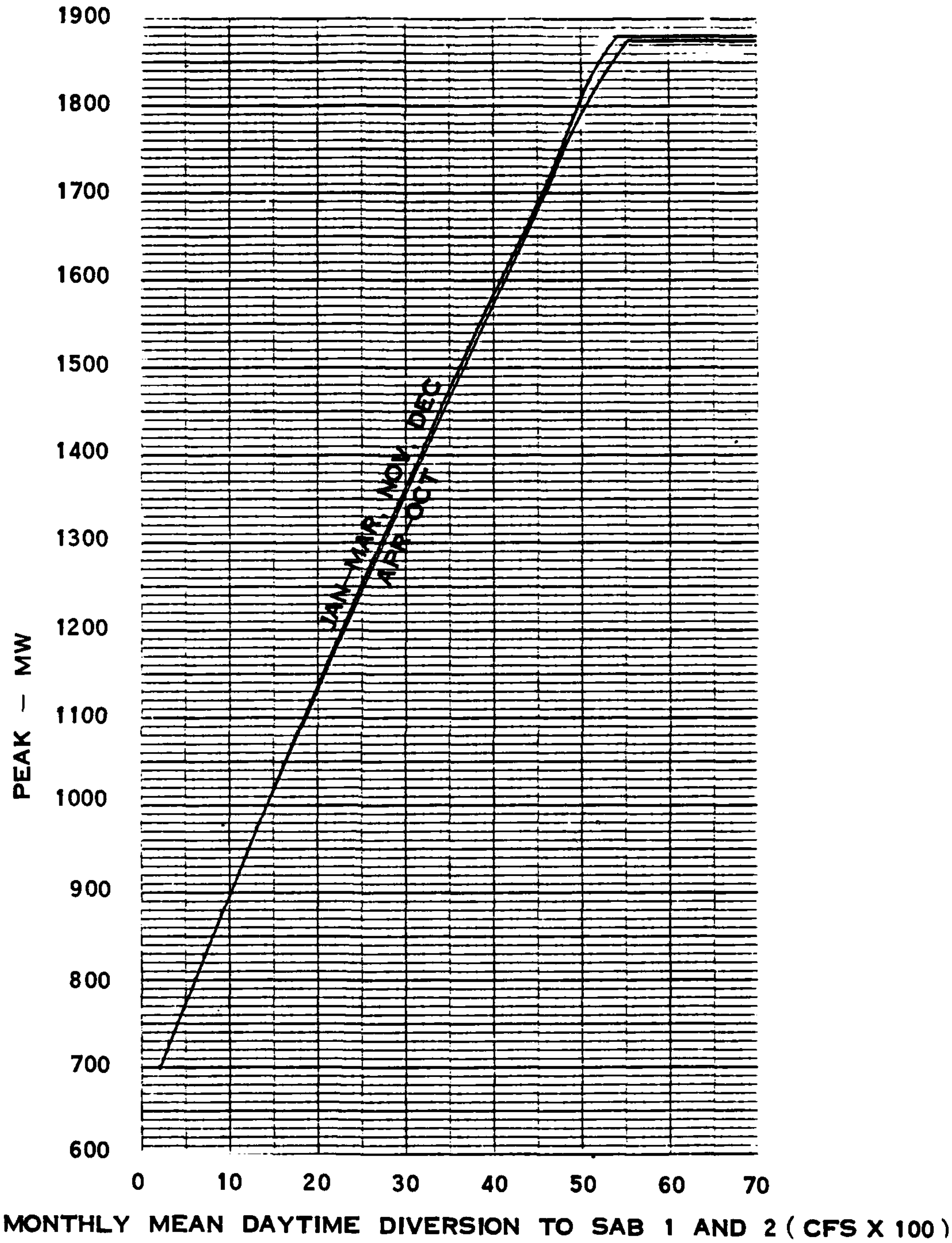
NIAGARA RIVER DAILY ENERGY GAIN OR LOSS FROM OPERATION OF S. A. B. NO. 2 PUMP G. S. VERSUS INFLOW TO GRASS ISLAND POOL

FIGURE E-13



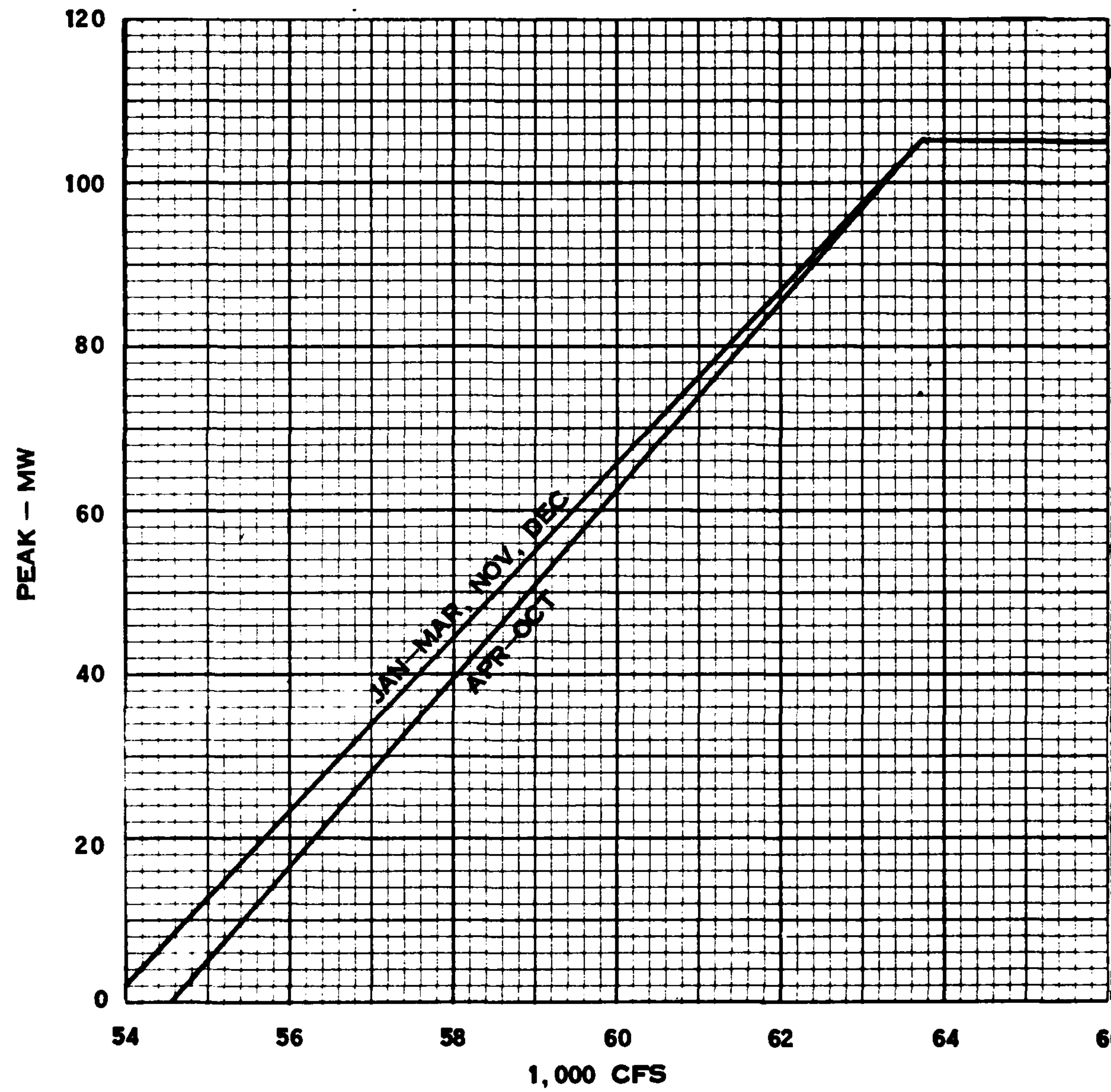
PEAK OUTPUT AT DECEW G. S.
RELATED TO MONTHLY MEAN FLOW DIVERSION

FIGURE E — 14



PEAK OUTPUT AT SAB 1 AND 2 AND P.G.S. RELATED TO MONTHLY MEAN DAYTIME FLOW DIVERSION TO SAB 1 AND 2

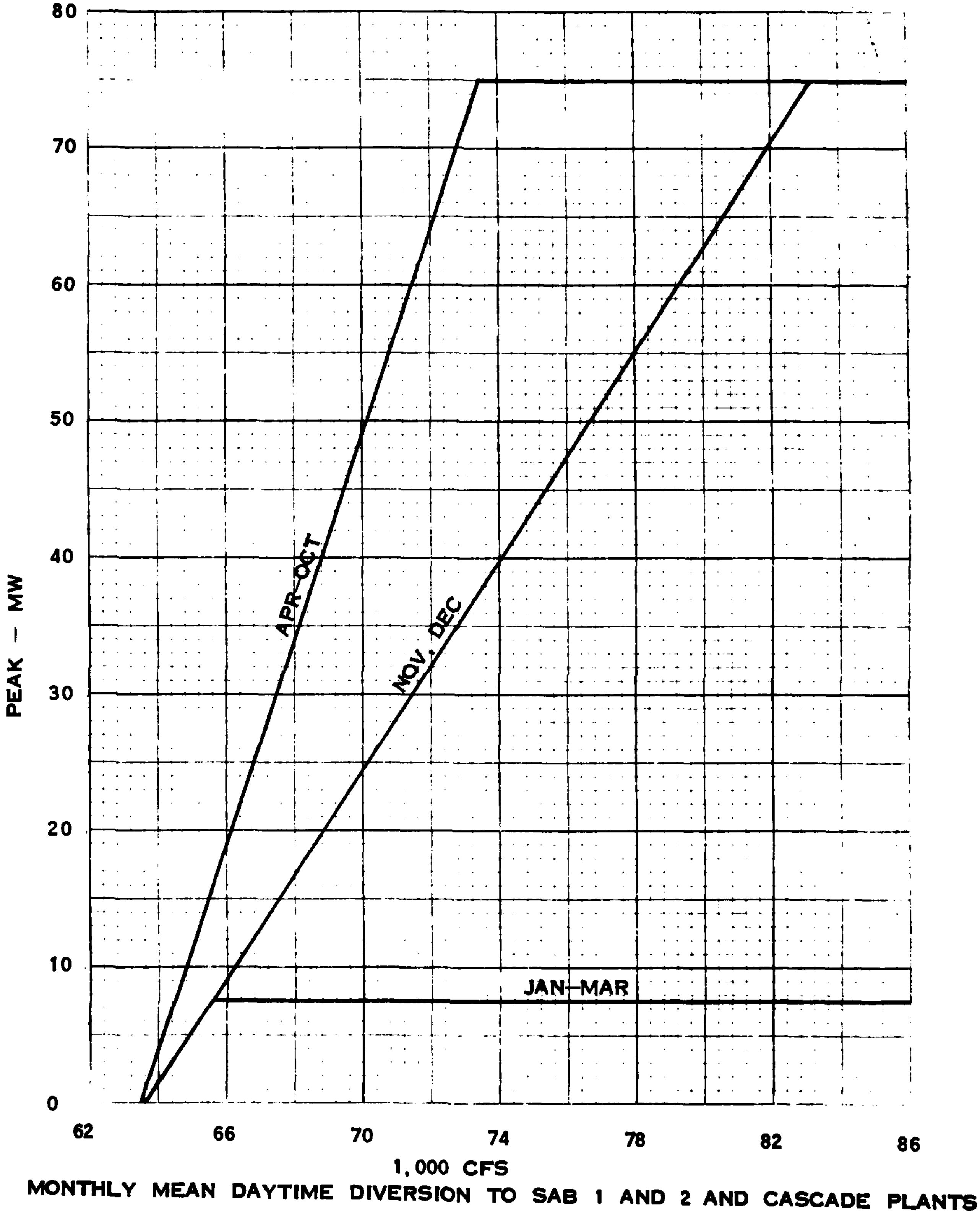
FIGURE E – 15



MONTHLY MEAN DAYTIME DIVERSION TO SAB 1 AND 2 AND THE CASCADE PLANTS

PEAK OUTPUT AT ONTARIO POWER GS RELATED TO MONTHLY MEAN DIVERSION TO SAB 1 AND 2 AND THE CASCADE PLANTS

FIGURE E – 16



PEAK OUTPUT AT CNP RELATED TO
MONTHLY MEAN DIVERSION TO SAB 1 AND 2 AND CASCADE PLANTS

FIGURE E — 17

(6) The Moses energy outputs are computed from the diversion to Moses, in item (2) and gross head, item (5), using the turbine-generator output characteristics.

(7) The maximum amount of water that can be discharged through a Moses plant unit for high head is controlled by the maximum permissible generator output which is considered to be 175 MW. For gross heads less than 304 feet, the maximum unit discharge is controlled by the full gate flow. The canal forebay elevation is assumed to be limited to a minimum of 540.0.

(8) Thirteen Moses plant units are assumed to be available each month, except during April, May, September and October when only twelve units were assumed to be available to allow for maintenance.

(9) The maximum diversion to the Moses plant is the flow that would load the available Moses units to 175 MW or to full gate discharge or produce a canal forebay level of 540.0, whichever is the least.

(10) The preceding parameters generally define the constraints of the U.S. Niagara plant to divert Niagara flows for power production. Essentially, the U.S. Niagara plant has the capability to divert about 100,000 cfs or about 85,000 cfs during peaking hours.

Based on the regulation plans studied, the effect of changes to Lake Erie outflows would be limited or minor. Within this context it is possible for the U.S. Niagara plant to divert its entitlement for virtually the entire range of flows for the basis-of-comparison and for the plans under study. For only up to about four percent of the flows during four or five of the summer months, could the entire entitlement not be taken. Therefore, it is convenient to calculate the difference in wastage between the basis-of-comparison and the plan under study, and evaluate the difference in terms of energy lost at the rate of 22 kWh for each cfsh wastage. It should be noted that the plant efficiency is essentially 22 kW/cfs throughout the range of flows under discussion.

3.2.7 Peak Output Computations for United States Plants

The peak output, or capacity available from the existing Moses plant and the Lewiston pump generating plant depends on the net head and flows available. The pumped storage reservoir requires sufficient water to refill it for each pump-generating cycle.

The assessment of any regulation plan is determined by comparing that plan to the basis-of-comparison. Changes in flows in the plans under study are small compared to the basis-of-comparison. The majority of changed flows occur during the higher lake levels and outflows, when available capacity is unaffected. It is only during the lower range of flows that any changes to flows would affect capacity from the hydro plants.

The effect of regulation would be to change the flow duration available for power diversion. The method of computing the peak capacity at U.S. Niagara plant is described in the following paragraphs.

(1) Chippawa-Grass Island Pool inflow durations for each calendar month for the basis-of-comparison and each regulation plan are derived from the monthly data described in Subsection 3.2.2. (1) and (2).

(2) The diversion available to the United States for any given Chippawa-Grass Island Pool inflow is computed. The percent of time each diversion would be available is developed from the Chippawa-Grass Island Pool inflow duration data.

(3) Maximum Niagara Power Project output is reached when all available Lewiston Pumped Generating units are operated as generators at maximum output. For critical power system conditions, the pump generators would be used to help carry the daily peak load even if this meant diverting less water from the Niagara River than the U.S. entitlement at the time. For peak loads of one or two hours duration, operating experience has shown that it is usually possible to store such unused water temporarily in the Chippawa-Grass Island Pool. For very low flow conditions, the maximum power output is limited by the amount of water which can be diverted from the Niagara River.

(4) The amount of water which can be withdrawn from the pumped-storage reservoir and the amount of power which can be generated at the pump-generating plant, depends upon the water level prevailing in the reservoir. A review of operating records indicates the suitability of the following reservoir level-probability relationship:

Reservoir Water Surface Elevation	Probability of Being at Tabulated Elevation at Time of System Daily Peak Load
650.0	47 percent
645.0	31 percent
640.0	15 percent
635.0	7 percent

(5) It is established electric utility practice to provide periodic and systematic preventive maintenance for all generating units. The percent of time each of the 25 units at Niagara would be out of service for maintenance depends upon the maintenance interval, the number of shifts worked by maintenance personnel, and the number of shifts required per unit to perform the necessary work. Present practice is bi-annual maintenance at the Lewiston Plant and a 36-month interval at the Moses Plant. The Lewiston units are normally maintained during the non-tourist season, while the Moses units are maintained during the tourist season when average flows available for diversion are low.

(6) The discharge from the Lewiston plant is added to diversions available from the river. This is the maximum amount of water available for the Moses plant and may be more than can be used by the plant. If

the diversion from the river and maximum Lewiston discharge exceed the flow required for maximum Moses plant generation, the flow to be diverted from the river is reduced until maximum Moses plant generation is achieved. If the sum of Lewiston pump storage discharge and flow available from the river is insufficient to load all Moses units to full gate discharge, then flow is controlling, and computation is made to determine the highest output which can be achieved for that flow.

(7) Maximum project capacity is the sum of Moses and Lewiston power outputs. For each duration of river flow for which there is a loss of capacity, the change in capacity is computed as described above, and the percent of time, multiplied by the changed capacity gives the results in terms of MW months. From these units an equivalent economic value can be determined.

Section 4

MOSES-SAUNDERS (ST. LAWRENCE) POWER PLANTS

4.1 General Description

There are two hydroelectric power plants in the International Section of the St. Lawrence River: The Robert H. Saunders Generating Station of Ontario Hydro and the Robert Moses Power Dam of the Power Authority of the State of New York, which are combined to form a single structure. The rated head of both plants is 81 feet and each plant has 16 units and a total installed capacity of 912,000 kW. A general location map of these plants is shown in Figure E-18.

4.2 Methodology for Determining Energy and Peak Capacity

The peak and energy outputs obtainable from the Saunders plant and Moses plant were computed monthly (half monthly for April and December) over the 77-year period January 1900 to December 1976. Monthly or half monthly energy outputs were divided into daytime (16 hours/day) and nighttime (eight hours/day) generation. The method of computing the total daytime and nighttime energy outputs and the total peak outputs each month or half-month is described in the following subsections.

4.2.1 Assumptions

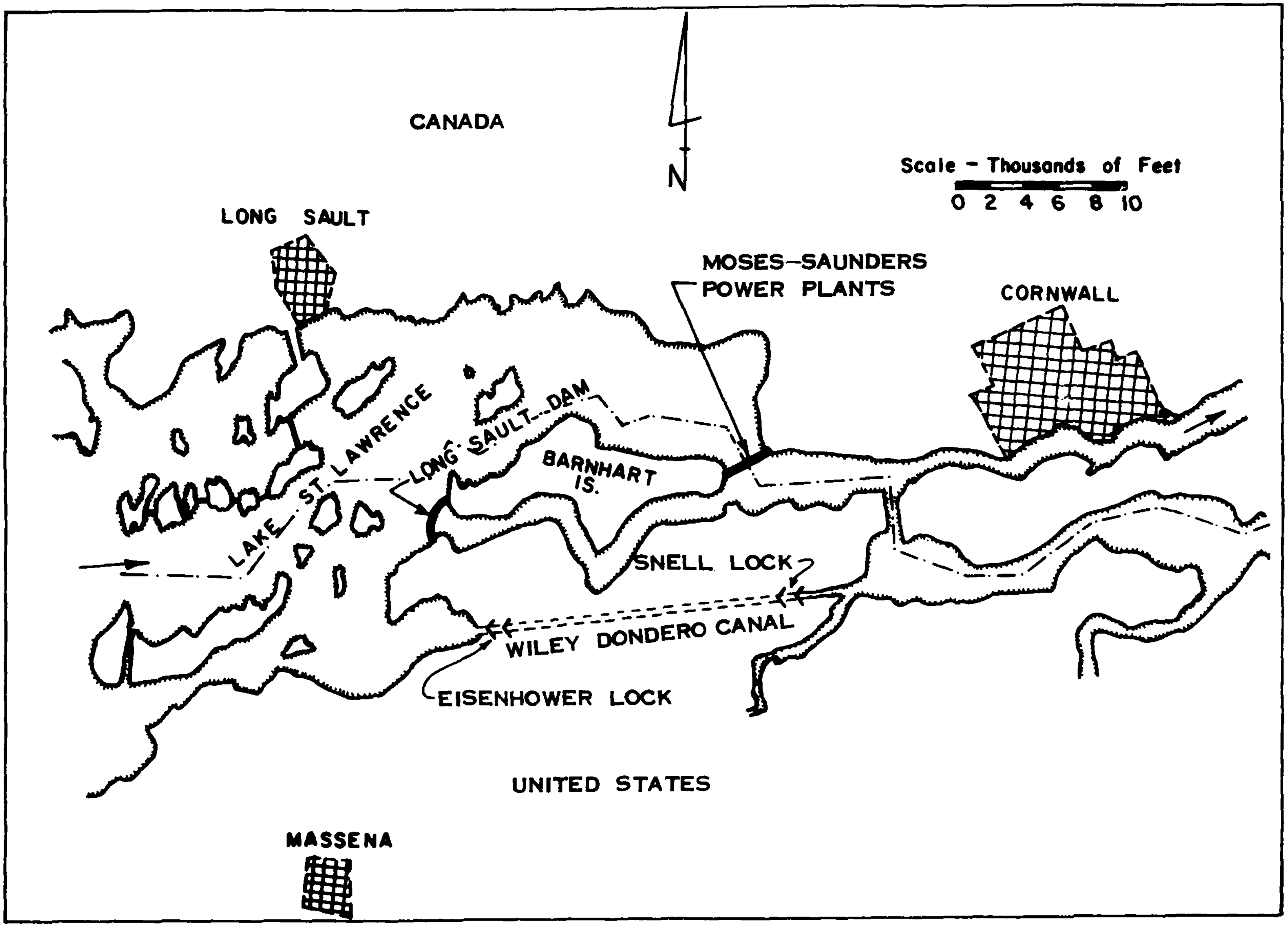
The assumptions adopted for computing the daytime energy, nighttime energy, and capacity outputs for any given regulated mean monthly Lake Ontario outflow and level combination are as follows:

(1) Since the maximum operating efficiencies of the Saunders and Moses (St. Lawrence) units are essentially the same, the total or combined energy and peak capacity outputs from both plants were computed and divided equally between them.

(2) The 1985 non-power flow diversions would consist of the estimated 1985 navigation requirements, the estimated 1985 Cornwall Canal requirements, and the Massena Canal requirements, which were assumed to be the same as those of 1963-66. They are summarized in Table E-5 and the total is rounded to the nearest 1,000 cfs. The Massena and Cornwall canals bypass the power dam to supply water for municipal requirements, and flushing for water quality purposes. The Cornwall municipal requirement is less than 5 cfs and was neglected in this study.

(3) The navigation season extends from April 1 to December 15.

(4) The daily peaking and weekly ponding test limits authorized by the International Joint Commission on a test basis are in effect.



ST. LAWRENCE RIVER - GENERAL LOCATION OF MOSES-SAUNDERS HYDROELECTRIC POWER PLANTS

FIGURE E - 18

Table E-5

Assumed 1985 Non-Power Flow Diversions

Month		Cornwall and Wiley-Dondero Canals (cfs)	Municipal Water Requirements Massena Canal (cfs)	Total (cfs)
January		0	30	0
February		0	30	0
March		500	30	1,000
April	(1-15)	1,200	30	1,000
	(16-30)	2,400	30	2,000
May		2,700	30	3,000
June		2,800	30	3,000
July		2,700	40	3,000
August		2,600	40	3,000
September		2,600	40	3,000
October		2,600	40	3,000
November		2,700	30	3,000
December	(1-15)	1,600	30	2,000
	(16-31)	0	30	0

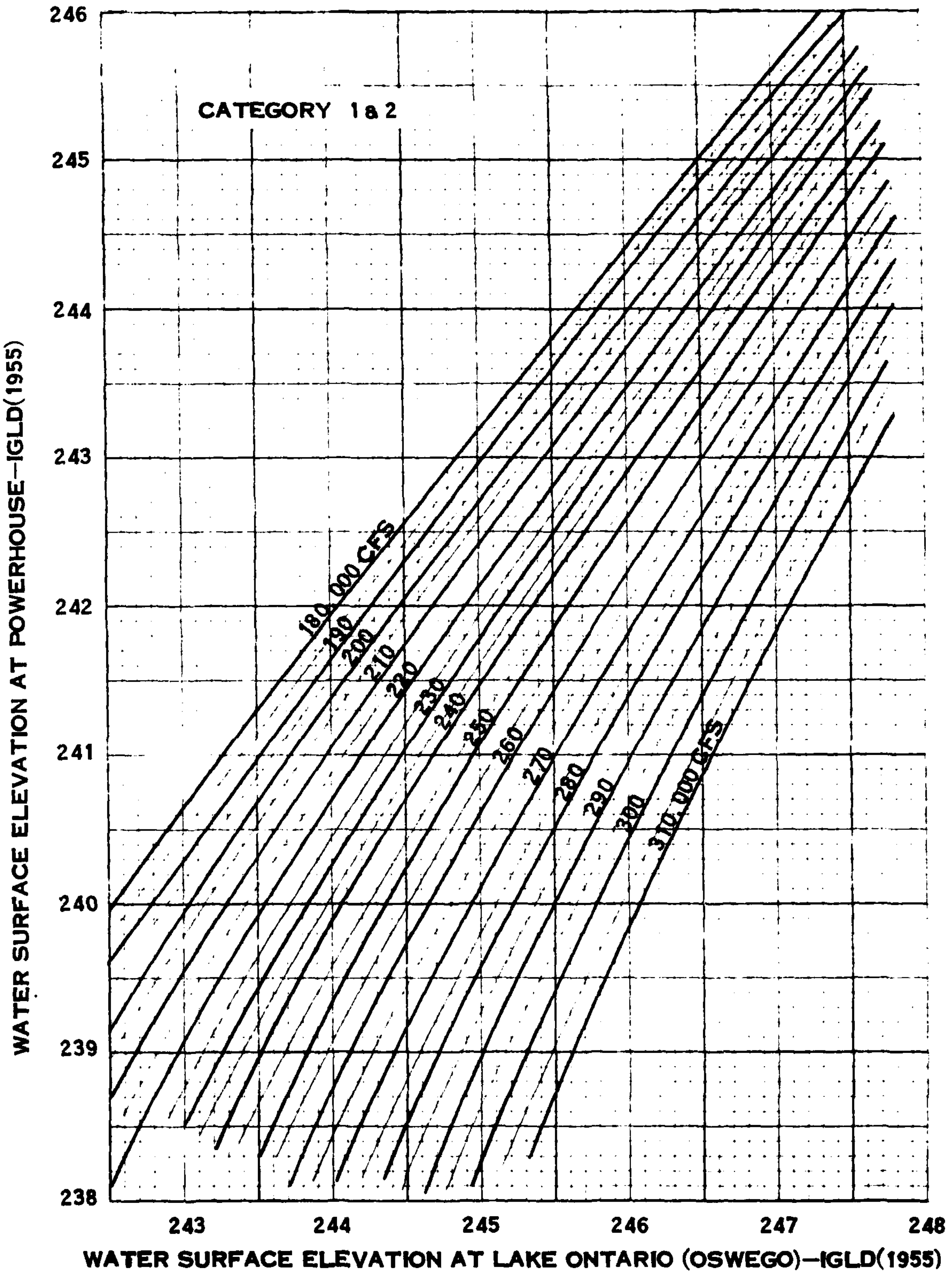
4.2.2 Basic Data

The basic data used are Lake Ontario monthly mean outflows and levels for the basis-of-comparison and each regulation plan.

4.2.3 Derived Data

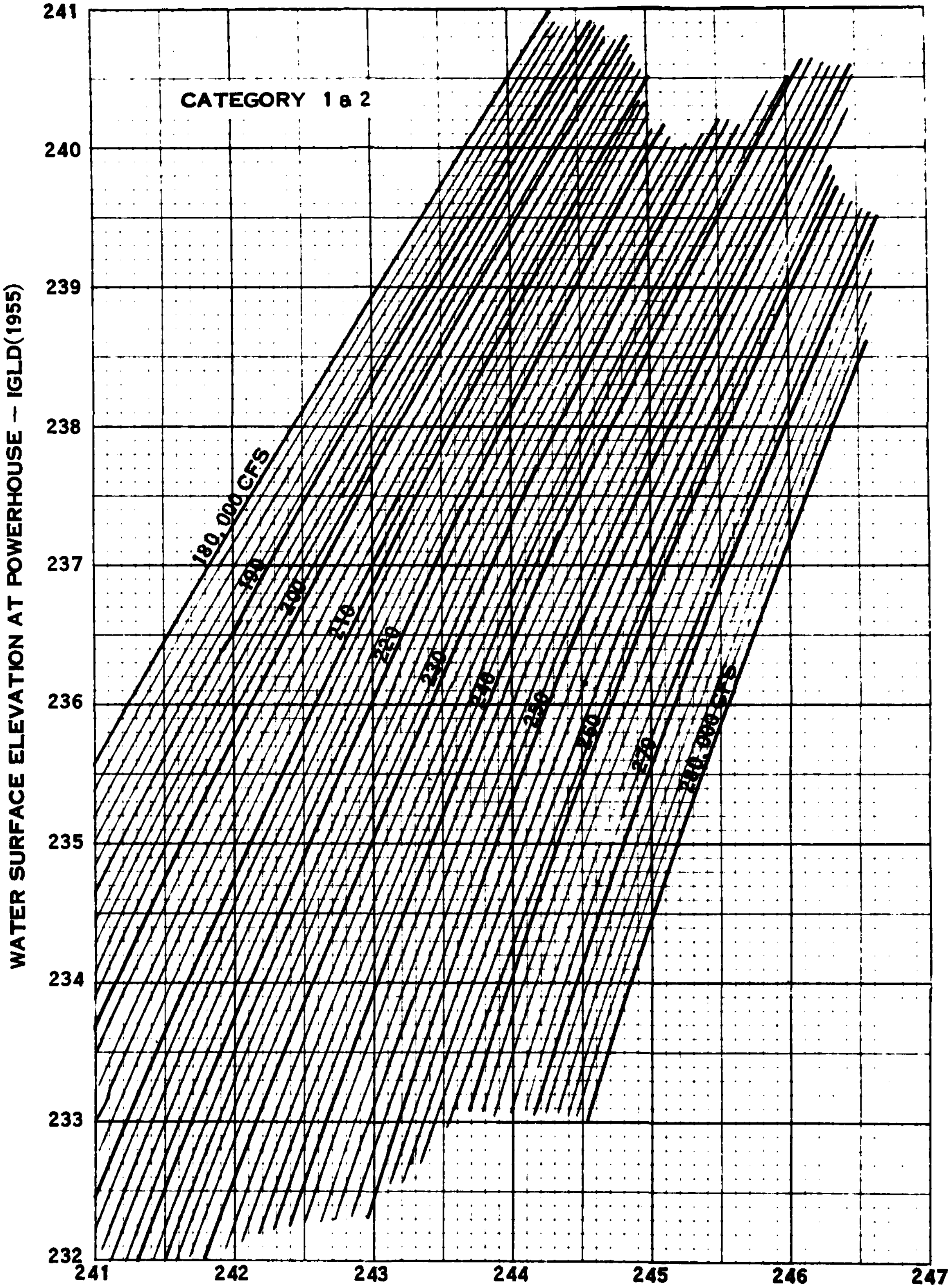
(1) Backwater Slopes from the Moses-Saunders Forebay to Lake Ontario for Categories 1 and 2: For the open water season (April to December) backwater slopes were derived from a unit fall relationship between the Oswego, New York gauge and the forebay, developed from observed levels and lake outflows over the period May 1959 to July 1966. The backwater slope curves are shown on Figure E-19. For the ice cover season (January to March) the backwater slopes were based on the results of design studies and model tests. They are shown on Figure E-20.

(2) Backwater Slopes from Moses-Saunders Forebay to Lake Ontario for Category 3: Under Category 3 it would be necessary to provide additional channel capacity in both the Canadian and International Reaches of the St. Lawrence River. In order to evaluate the potential power gain at the Moses-Saunders Generating Stations, revised channel losses between Lake Ontario and the power dam were required. The following method and assumptions were used to estimate the revised backwater slopes:



BACKWATER SLOPES LAKE ONTARIO TO
MOSES—SAUNDERS POWERHOUSE OPEN WATER CONDITIONS

FIGURE E — 19



BACKWATER SLOPES LAKE ONTARIO TO
MOSES—SAUNDERS POWERHOUSE ICE COVER CONDITION

FIGURE E — 20

(a) Open Water Conditions

The original channel enlargements were designed to satisfy the critical profile under Regulation Plan 12-A-9. Under this plan the minimum forebay elevation occurred with a Lake Ontario level of 244.33 feet and a discharge of 296,000 cfs. To satisfy the various criteria under the adjusted basis-of-comparison and Plan 6L an additional capacity of 4,000 cfs is required, under Plan 25N an additional 5,000 cfs is necessary, and under Plan 15S an additional 6,000 cfs is necessary.

The existing open water backwater slopes are based on a straight line unit fall relationship having the equation:

$$MWS = 225.807 + \frac{0.13652\ Q \times 10^{-3}}{F^{1/2}}$$

where MWS = mean water surface elevation

$$= \frac{\text{Lake Ontario elev + Moses - Saunders forebay elev}}{2}$$

Q = Lake Ontario outflow in cfs, and

F = fall or head loss between Lake Ontario and the Moses-Saunders forebay

Assuming the same Lake Ontario and forebay levels and consequently the same mean water surface elevation, revised $\frac{Q}{F^{1/2}}$ values were computed for increased flows of:

Adjusted Basis-of-comparison and Plan 6L	296,000 + 4,000 = 300,000 cfs
Plan 25N	296,000 + 5,000 = 301,000 cfs
Plan 15S	296,000 + 6,000 = 302,000 cfs

Revised straight line relationships were drawn through these points parallel to the present line.

The equations for the increased capacities are:

Adjusted Basis-of-comparison and Plan 6L
$$MWS = 225.605 + \frac{0.13652\ Q \times 10^{-3}}{F^{1/2}}$$

Plan 25N
$$MWS = 225.555 + \frac{0.13652\ Q \times 10^{-3}}{F^{1/2}}$$

Plan 15S
$$MWS = 225.505 = \frac{0.13652\ Q \times 10^{-3}}{F^{1/2}}$$

The Moses-Saunders headwater levels were then computed based on these equations and the respective Lake Ontario levels and outflows.

(b)Ice Cover Conditions:

As the present St. Lawrence River backwater slopes for the ice cover period are not based on a single unit fall relationship it was not possible to use the same approach as used for the open water condition. In order to arrive at an approximate change in relationship it was decided to use a percentage adjustment to the present slopes.

The following percentages were applied:

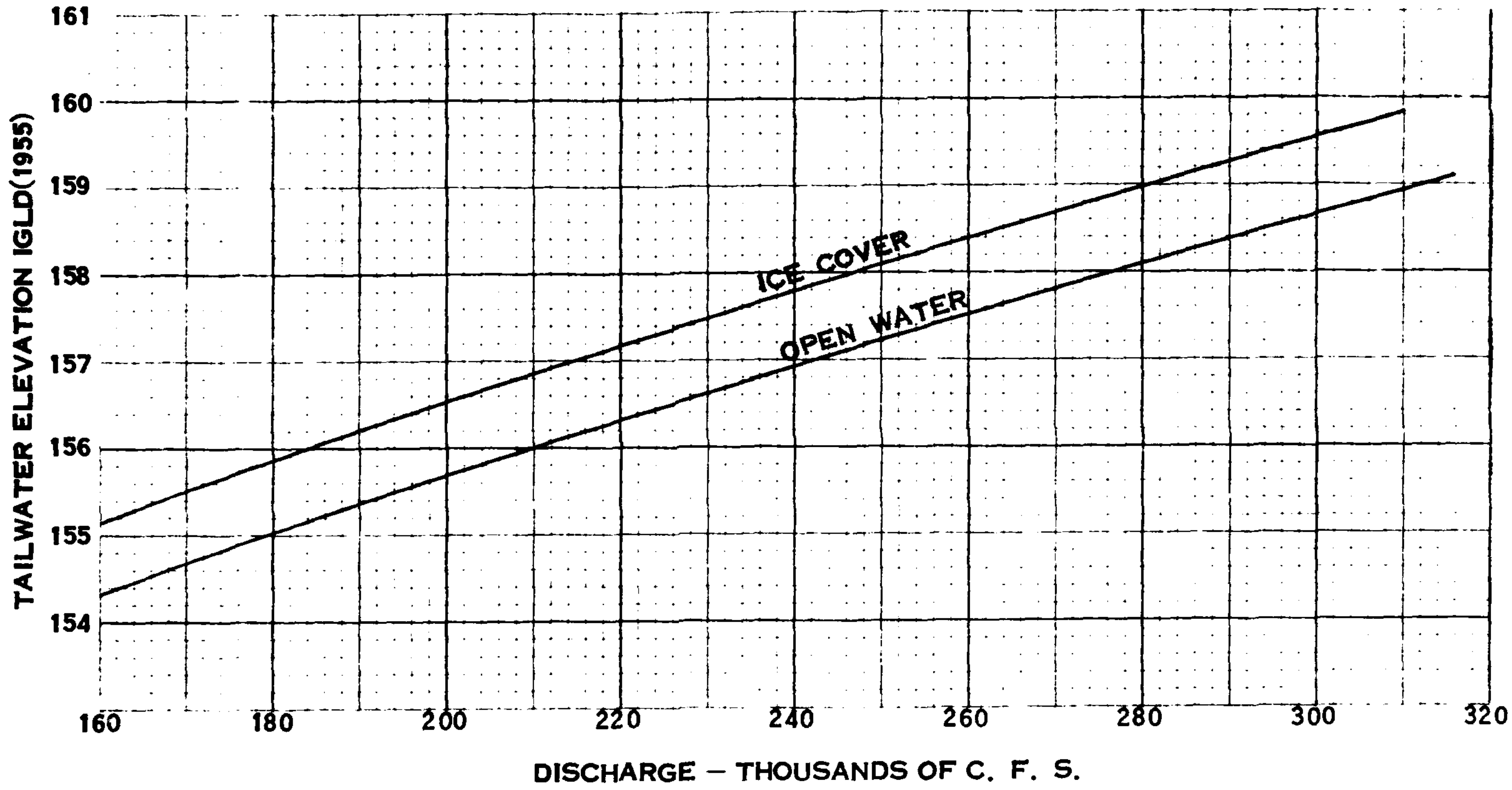
Adjusted Basis-of-Comparison	
and Plan 6L	(4,000/296,000) x 100 = 1.35 percent
Plan 25N	(5,000/296,000) x 100 = 1.69 percent
Plan 15S	(6,000/296,000) x 100 = 2.03 percent

The forebay elevations were then computed for any given Lake Ontario level and outflow by; reducing the discharge by the respective percentage; determining the forebay level based on the existing relationship with the given Lake Ontario level and the calculated reduced flow; using the computed forebay level with the original given outflow to calculate the power output.

It is considered that this approach gives the best approximation of revised conditions, taking into account that actual ice cover losses vary significantly from year to year and in fact from week to week.

(3) Tailwater Stage-Discharge Relations: These relationships have been derived for both open water and ice cover seasons from mean daily records of the Saunders and Moses tailwater elevations (averaged) and total plant discharge over the period June 1961 to September 1966. They are shown on Figure E-21.

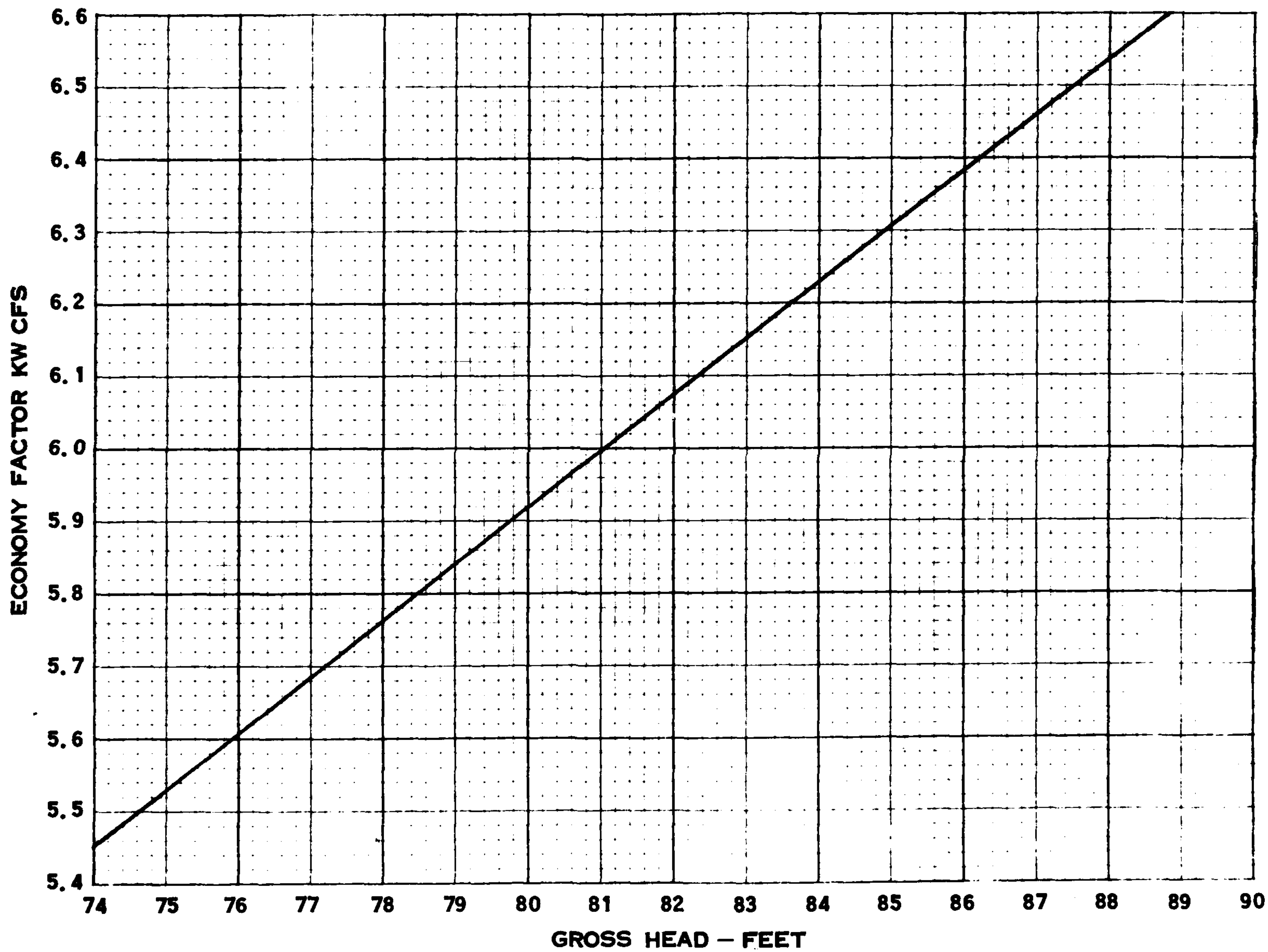
(4) Moses-Saunders Total Power-Discharge-Head Relationships: For the maximum efficiency operating range (total plant discharges of less than about 280,000 cfs) a relationships between the average economy factor of the two plants and gross head was derived from unit performances actually attained in normal operation. This relation is shown on Figure E-22. For the operating range beyond best efficiency (total plant discharges greater than about 280,000 cfs), a family of curves relating total plant output to discharge for a range of gross heads between 74 and 88 feet was derived from unit rating tables. These curves are shown in Figure E-23. If the calculated discharge for a given gross head exceeds the maximum output line shown in Figure E-23, the



NOTE
TAILWATER IS AVERAGE OF MOSES–SAUNDERS TAILWATER ELEVATION.
DISCHARGE IS COMBINED FLOW RECORDED THROUGH PLANTS.

TAILWATER STAGE – DISCHARGE CURVE

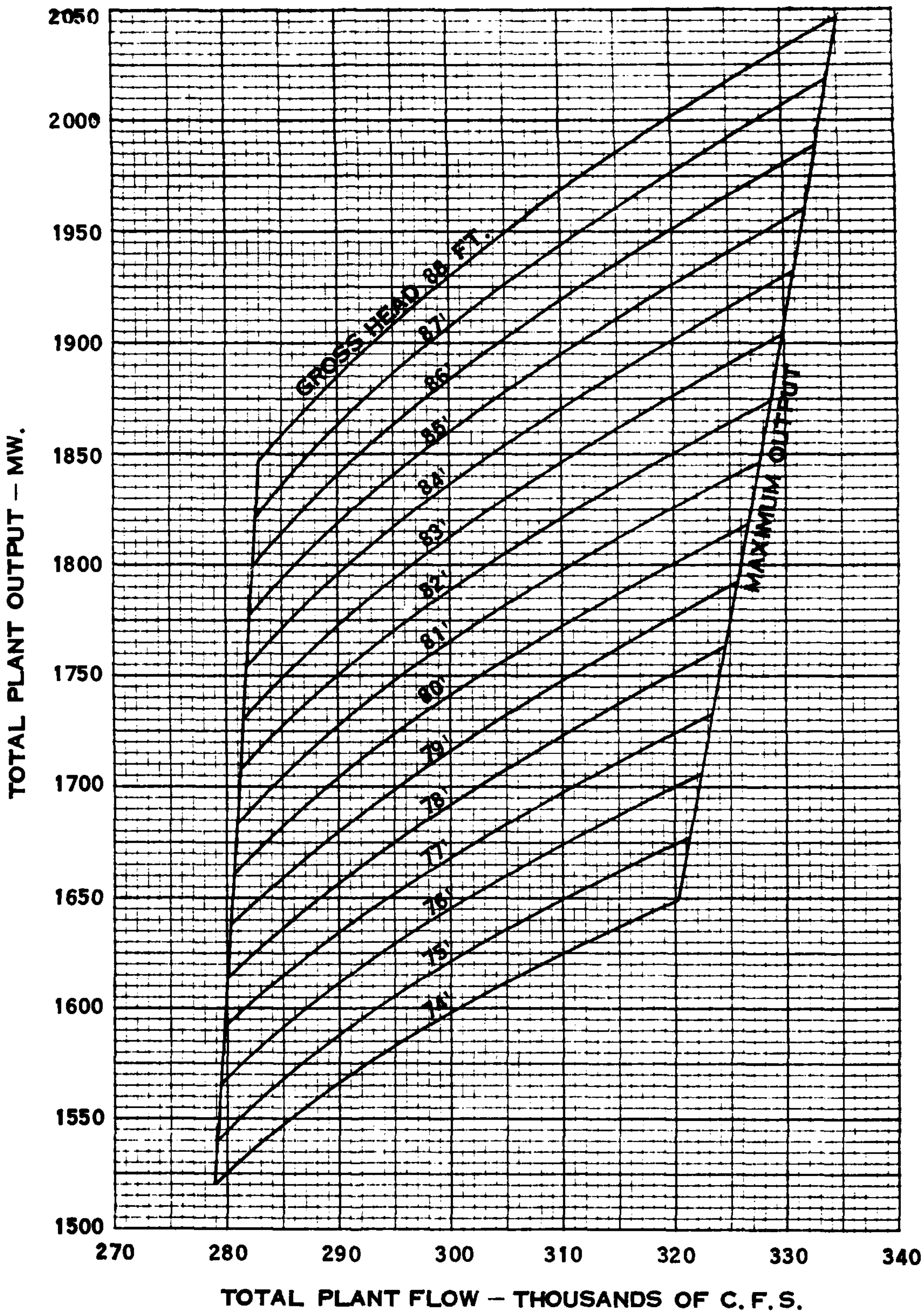
FIGURE E – 21



NOTE – DERIVED FROM UNIT PERFORMANCE ATTAINED IN NORMAL OPERATION

AVERAGE ECONOMY FACTOR FOR MOSES–SAUNDERS PLANTS
VERSUS GROSS HEAD (BEST EFFICIENCY OPERATING RANGE)

FIGURE E – 22



NOTE — DERIVED FROM UNIT RATING TABLES

COMBINED MOSES—SAUNDERS PLANT OUTPUT — DISCHARGE RELATIONSHIP

FIGURE E — 23

output is determined, for the given gross head, from the maximum output line

4.2.4 Determination of Energy and Peak Outputs

(1) The Moses-Saunders forebay elevation, applicable to both daytime and nighttime energy and to peak, was determined from backwater slope curves relating Lake Ontario level and outflow to forebay level. The Lake Ontario levels and outflows used in the determinations were the regulated mean monthly values given in the basic data. The forebay level was limited to a maximum elevation of 242.0 feet and a minimum elevation of 234.0 feet.

(2) The total plant discharge for peak output determination was computed as the Lake Ontario regulated mean monthly or outflow, less the estimated 1985 non-power flow diversions, plus 30,000 cfs up to a total of 280,000 cfs during the navigation season (April second half to December first half) or plus 38,000 cfs up to a total of 280,000 cfs during the non-navigation season (December second half to April first half).

(3) The total plant discharges for daytime and nighttime energy determinations were computed as the Lake Ontario regulated outflows less the estimated 1985 non-power flow diversions, plus 15,000 cfs during the daytime or minus 30,000 cfs during the nighttime up to a total of 280,000 cfs. The effect of weekly ponding upon energy production during the non-navigation season was ignored because it was not considered to be significant. In all cases, if the monthly flows exceed 280,000 cfs no additional discharge is added.

(4) Moses-Saunders tailwater elevation for computing peak output and daytime and nighttime energy outputs was determined from the tailwater stage-discharge relationship, Figure E-21, using the appropriate total plant discharge obtained as in item (2) and (3) above.

(5) Gross head for computing peak output and daytime and nighttime energy outputs was determined by subtracting the appropriate tailwater elevation obtained in item (4) from the forebay elevation obtained in item (1) .

(6) Total peak output was determined from Figure E-23 relating total plant output, discharge and head ; or, if the coordinate of head and discharge does not fall within the limits of these curves, by reading from the curve (Figure E-22) relating average economy factor (kW/cfs) to gross head, the appropriate economy factor and multiplying it by the total plant discharge. The peak output of the Saunders plant or the Moses plant was one half of the total peak output.

4.2.5 Determination of Total Daytime and Total Nighttime Energy Outputs

Total daytime and total nighttime energy outputs, in average MW were determined in the same manner as total peak output using the appropriate

plant discharge and gross head. These outputs were multiplied by the number of hours in the month or half-month that daytime or nighttime energy is produced (day - 16 hours x number of days, night - 8 hours x number of days) and the resultant values divided by two to give the daytime energy and the nighttime energy in MWh generated by the Saunders plant or the Moses plant.

Section 5

BEAUHARNOIS-LES CEDRES (ST. LAWRENCE) POWER PLANTS

5.1 General Description

The Beauharnois-Les Cedres developments are in Quebec, in the Soulanges section of the St. Lawrence River. This section of the River comprises the 15-mile stretch between Lake St. Francis and Lake St. Louis in which there is a total drop of 82 feet.

To harness the energy of the water in this turbulent reach, control dams were constructed at the exit from Lake St. Francis to allow the flow to be diverted from the natural channel into the Beauharnois Canal excavated on the south shore. After passing through the Beauharnois Canal and the 80-foot drop at the Beauharnois Powerhouse, situated at the outlet end of the canal, the water is discharged into Lake St. Louis. Figure E-24 shows the relationship of the canal to the St. Lawrence River.

The Beauharnois Canal is 15 miles long and 3,300 feet wide, and the average depth is more than 30 feet. The navigation channel which is 600 feet wide and has a minimum depth of 27 feet is located along the left bank of the canal. Two locks permit navigation to pass from the canal to Lake St. Louis.

It was planned to construct the Beauharnois powerhouse in three stages to keep pace with growing demand on the electrical system. Designed to have a capacity of 538,400 kilowatts from 14 generating units, the first stage rapidly took form and by the end of 1932, four units and two auxiliary units were in service. On August 25, 1951 the first units of the second stage were brought into service and all 12 units were in operation by the end of 1953 to bring total capacity at Beauharnois to 1,021,760 kilowatts. The first generating unit of Beauharnois 3 came into service in June 1959, with the last unit installed in early 1961. The Beauharnois powerhouse now has 36 turbines for a total capacity of 1,574,000 kilowatts, excluding the two auxiliary units.

The Les Cedres Generating Station which is located in the natural channel of the Soulange section came into service in 1914, with a capacity of 81,000 kilowatts from nine units. Other units were added as required until the plant reached its present capacity of 162,000 kilowatts from 18 units in 1924. At that time, it was the largest hydroelectric generating station in the world.

5.2 Methodology for Determining Energy Output at Beauharnois-Les Cedres Power Plants

The following assumptions, data and computation method were used in the determination of the energy output at the Beauharnois-Les Cedres Power Plants.

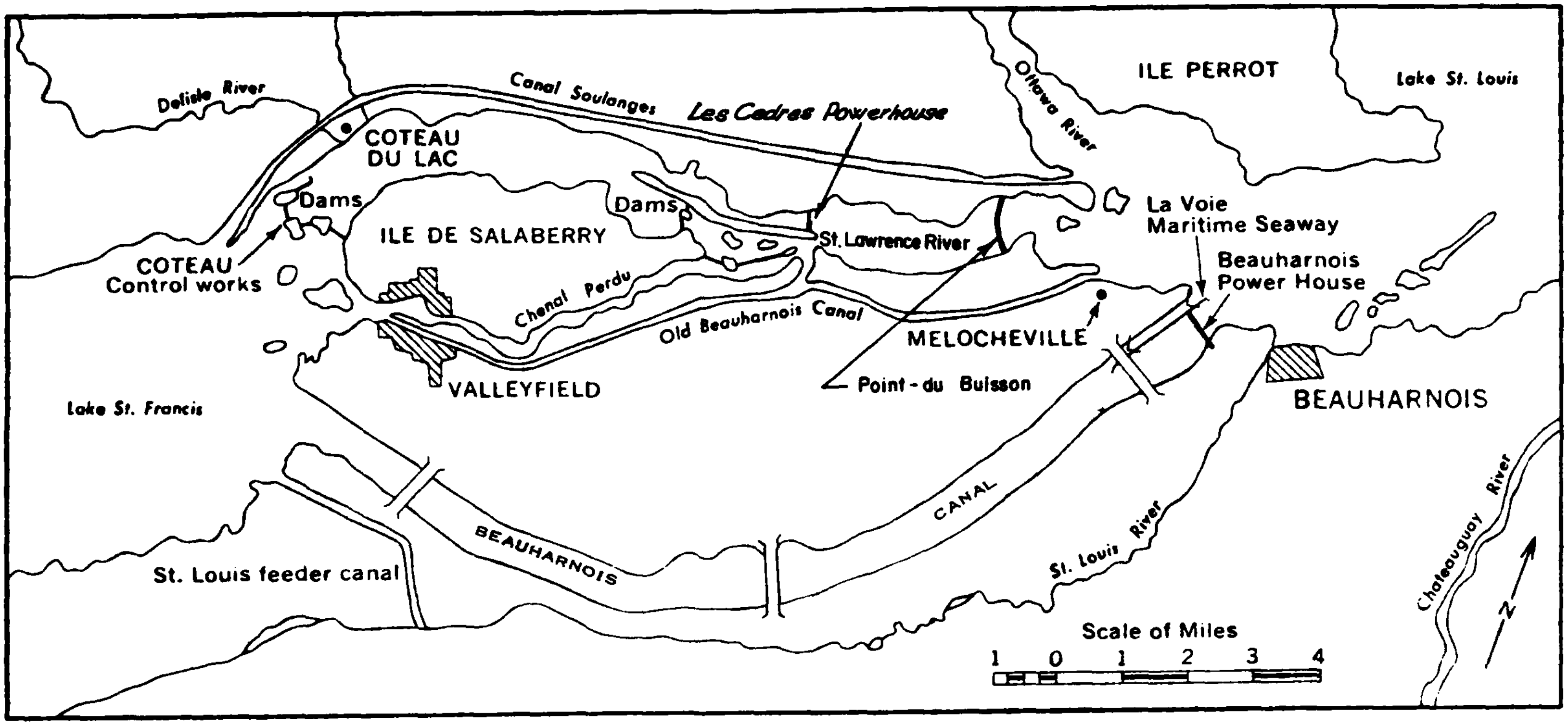


FIGURE E – 24

PLAN OF SOULANGE SECTION OF ST. LAWRENCE RIVER

5.2.1 Assumptions

A minimum flow of 10,000 cfs is a allowed in the Soulanges section of the St. Lawrence River, for environmental purposes. This gives the Les Cedres plant a minimum of 10,000 cfs.

5.2.2 Basic Data

The basic data comprise (a) the monthly mean outflows from Lake Ontario and Lake St. Louis for the basis-of-comparison and each regulation plan and are taken from Appendix A - Lake Regulation, Volume 2, Coordinated Basic Data; (b) the Chateauguay River monthly mean outflows from 1922 to 1966; and (c) the discharge of the Beauharnois Generating Station, after 1966.

5.2.3 Derived Data

(1) The Lake St. Francis local in flow is derived on a monthly mean basis as follows: for the period 1900 to 1922, the inflow was estimated from a watershed model; for the period 1922 to 1966, the inflow was derived from a linear regression of the River Chateauguay monthly mean outflows (Figure E-25); after 1966 the Lake St. Francis local inflow was derived from a simplified water budget of the Lake. This method was considered sufficiently accurate, since in 1975 the turbine rating of the Beauharnois Generating Station has been revised and the discharge from this Station has been corrected accordingly.

(2) The Lake St. Francis monthly mean outflow was obtained by adding the Lake Ontario monthly mean outflow and the Lake St. Francis monthly mean local inflow.

(3) The division of the Lake St. Francis outflow between Beauharnois-Les Cedres, Beauharnois navigation locks, and water which is unavilable for power production due to seepage, overflow, etc, is as follows:

The sum of the navigation requirements and the estimated water losses was subtracted from the monthly mean Lake St. Francis outflow (Table E-6). Since it was considered that a flow of 10,000 cfs at Les Cedres Generating Station is the minimum flow, this figure was subtracted from the total available discharge. The remaining available discharge was compared to the maximum permissible discharge at the Beauharnois plant, (Table E-7). When the calculated Beauharnois plant discharge exceeded the permissible discharge, the difference was transferred to Les Cedres plant giving a Les Cedres plant discharge of 10,000 cfs plus this difference. Similarly, the calculated discharge at the Les Cedres plant was compared to the maximum permissible discharge (Table E-7). When the calculated Les Cedres discharge exceeded the permissible discharge, the calculated discharge was reduced to the value of the permissible discharge, and the excess water was spilled.

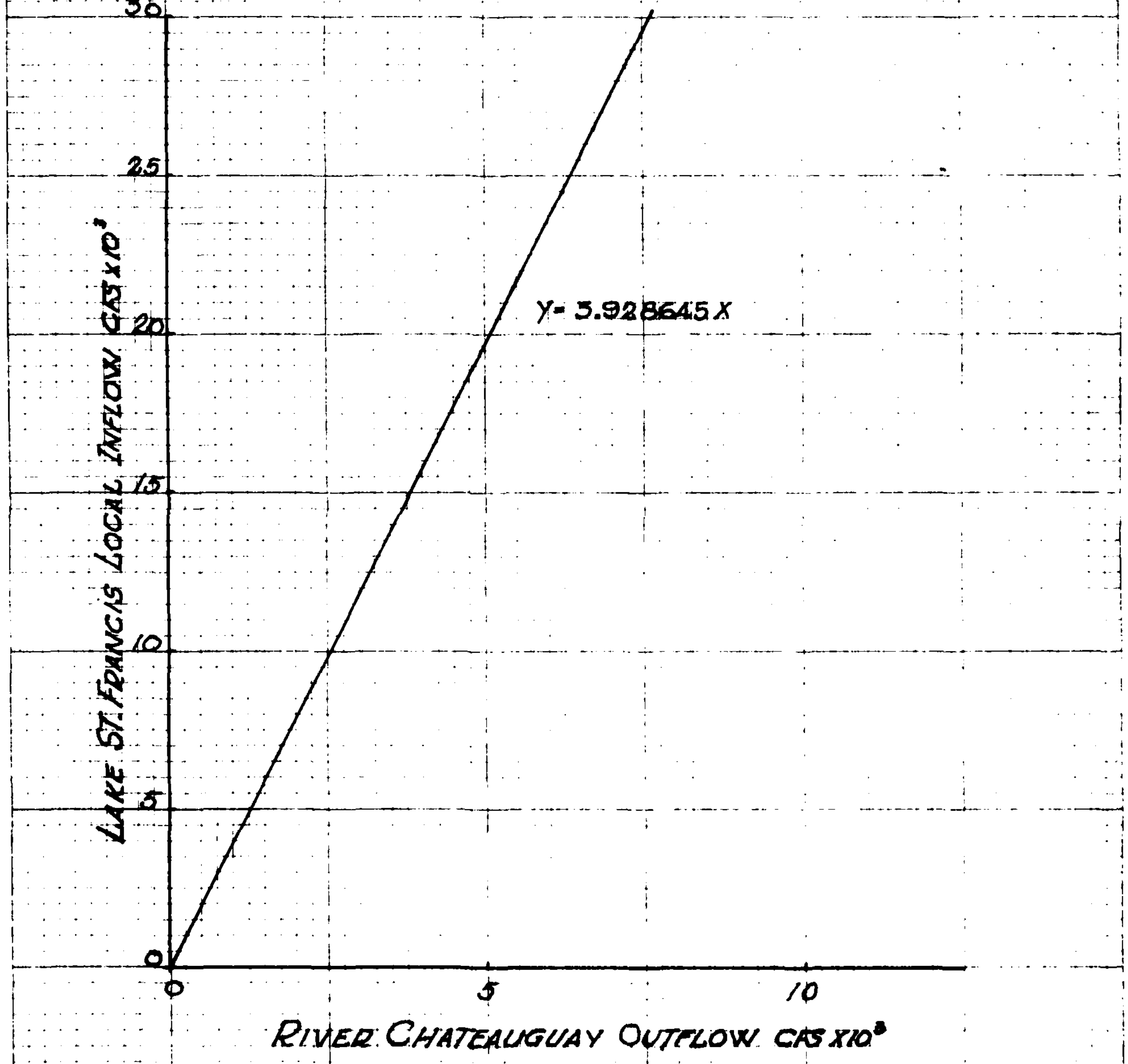


FIGURE E – 25

RELATIONSHIP BETWEEN RIVER CHATEAUGUAY OUTFLOW AND LAKE ST. FRANCIS LOCAL INFLOW

(4) The working head at the Beauharnois powerhouse was determined as follows:

The elevation at the Upper Beauharnois Lock was determined from a relationship between the Upper Lock levels and the total outflow of the Beauharnois Generating Station for each month of the year (Figure E-26). The elevation of Lake St. Louis was determined from two stage-discharge relationships for Lake St. Louis: one for the open water period from April to November inclusive, and the other for the ice cover period from December to March (Figure E-27).

The difference between the elevation of the Upper Beauharnois Lock and Lake St. Louis was considered gross head at Beauharnois powerhouse.

(5) The power-discharge-head relationship for Beauharnois was based on recorded values of the gross head, discharge, and equivalent power output for the period covering the years 1975 to 1979 inclusive. This period of record has been considered accurate due to the revision of the turbine rating made in 1975. Figure E-28 shows the new relationship curve used.

(6) The head at Les Cedres Powerhouse was determined for December to April, inclusive, by a linear relationship between the recorded head and the total outflow at the plant, (Figure E-29). For May to November, inclusive, the variations in the head are negligible, due to the control works at Pointe-du-Buisson which maintains Les Cedres tailrace at near-constant level (Figure E-24). The head was therefore fixed at 39.0 feet for these months.

(7) The power-discharge-head relationship for the Les Cedres plant was based on the recorded values for the years 1968 to 1971, inclusive (Figure E-30).

5.2.4 Computation of Power Output

Given the monthly mean outflows from Lake Ontario and Lake St. Louis, the following data were computed for each month:

(1) Lake St. Francis local inflow, from the relationship between Lake St. Francis local inflow and River Chateauguay outflow (figure E-26);

(2) Lake St. Francis outflow, by adding Lake Ontario outflow and Lake St. Francis local inflow (1);

(3) The division of Lake St. Francis outflow between the Beauharnois and Les Cedre plants as described in 5.2.3 (2);

(4) The Beauharnois powerhouse forebay elevation, obtained from the relationship between the Beauharnois Powerhouse outflow and the elevation at the Upper Beauharnois Lock (Figure E-26);

Relationship between the Upper Beauharnois lock level and the total outflow of Beauharnois Generating station for each month.

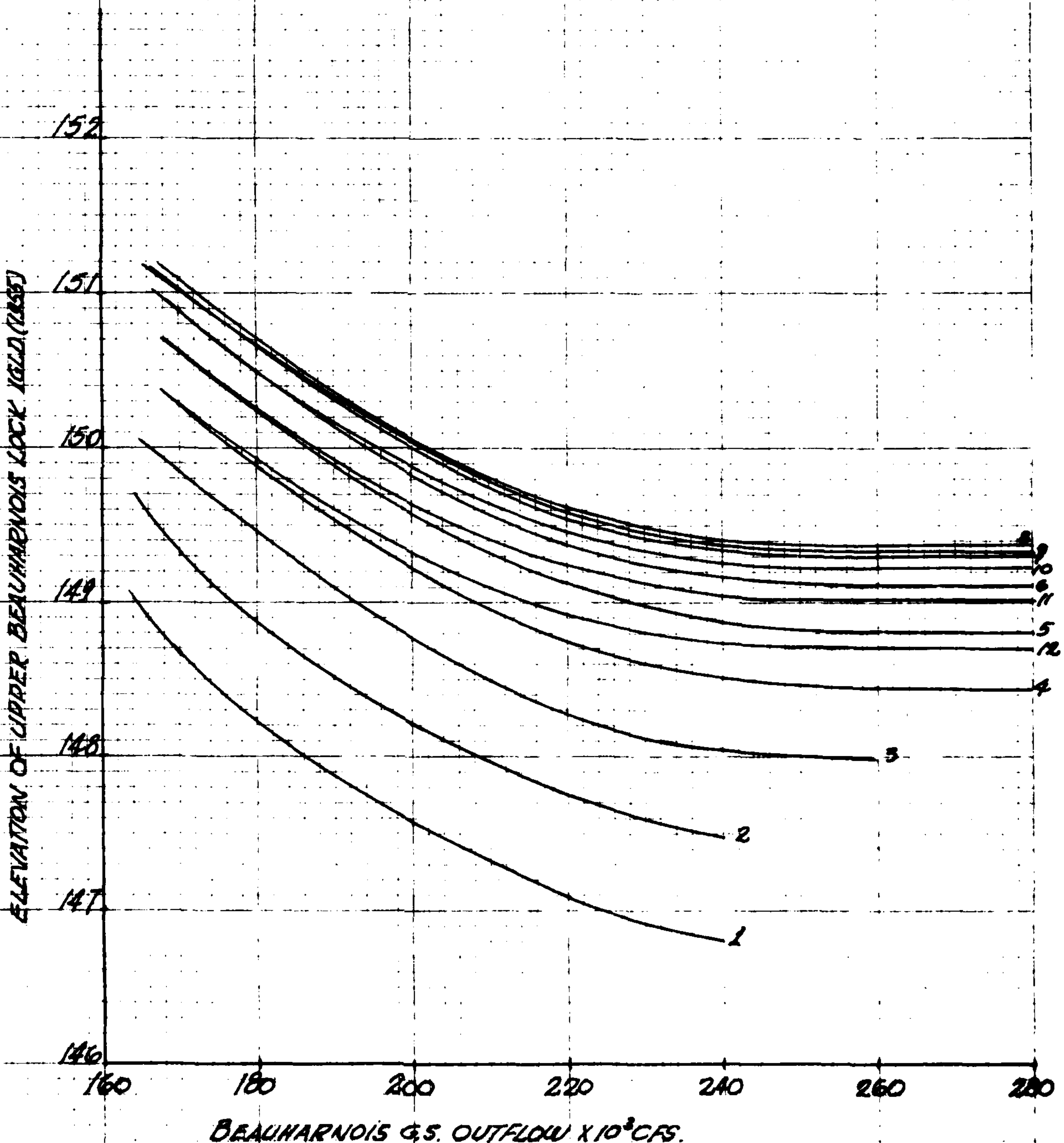


FIGURE E – 26

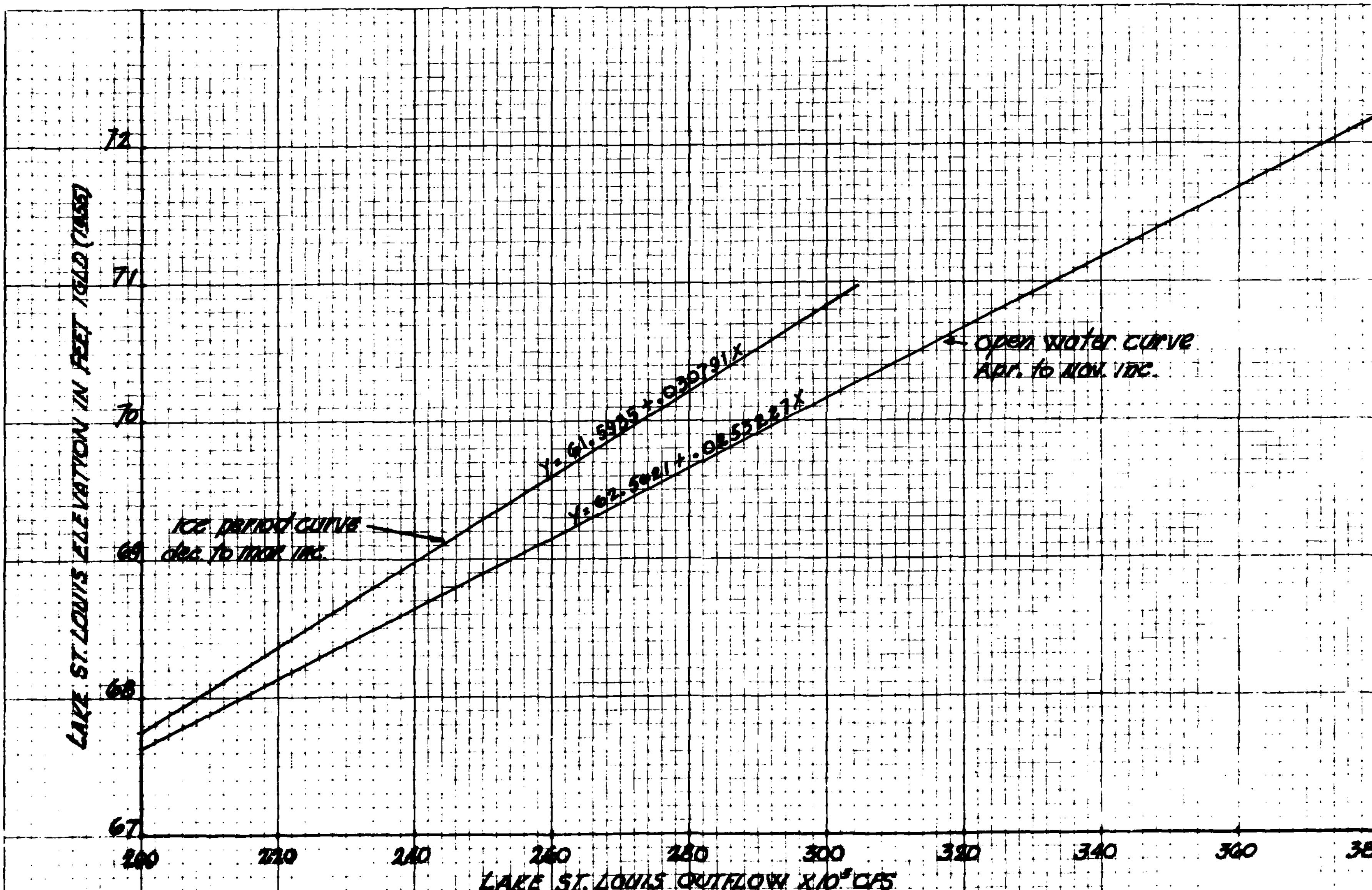


FIGURE E – 27

STAGE-DISCHARGE RELATIONSHIP FOR LAKE ST. LOUIS

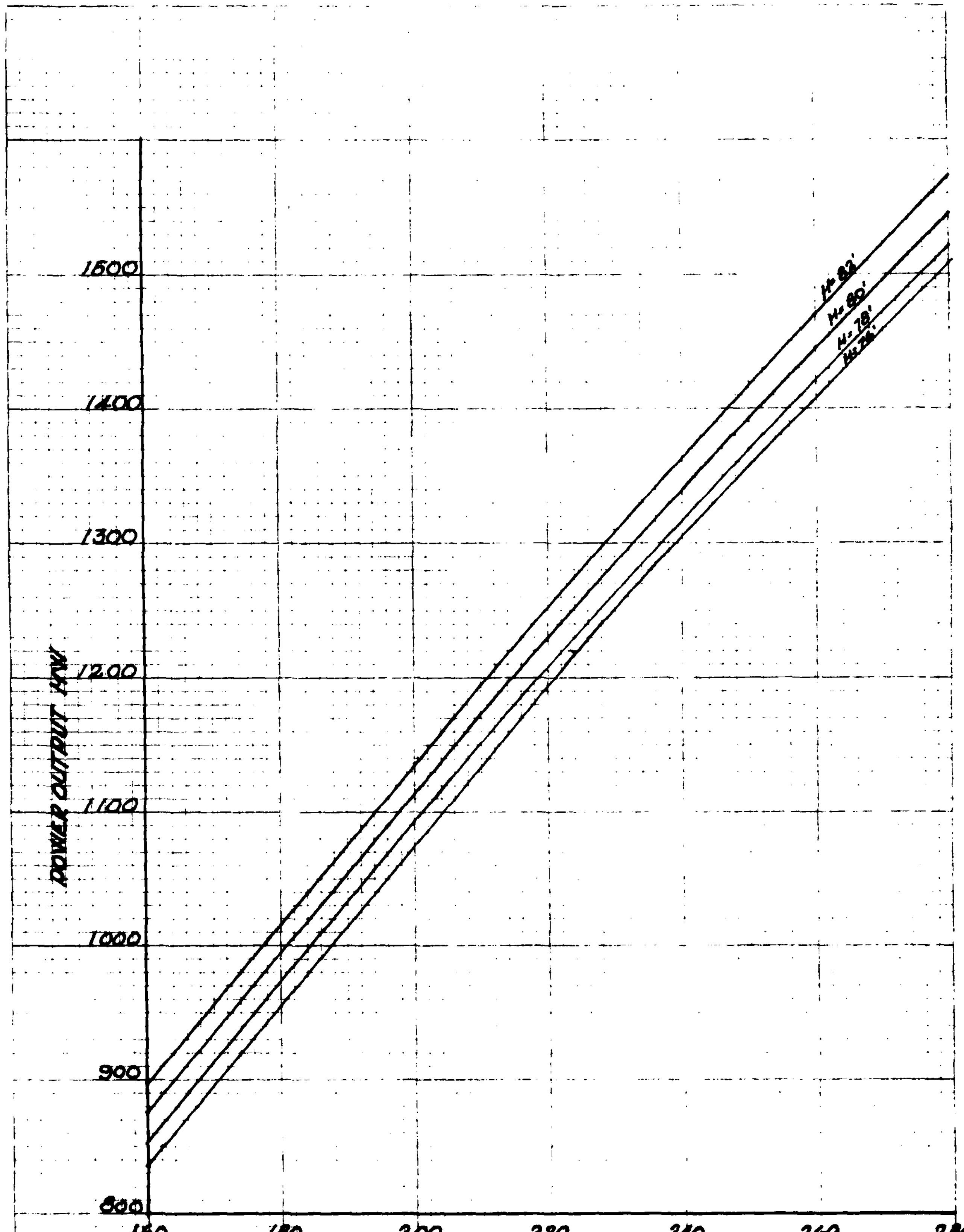


FIGURE E – 28

POWER OUTPUT - HEAD - DISCHARGE RELATIONSHIP FOR BEAUHARNOIS G.S.

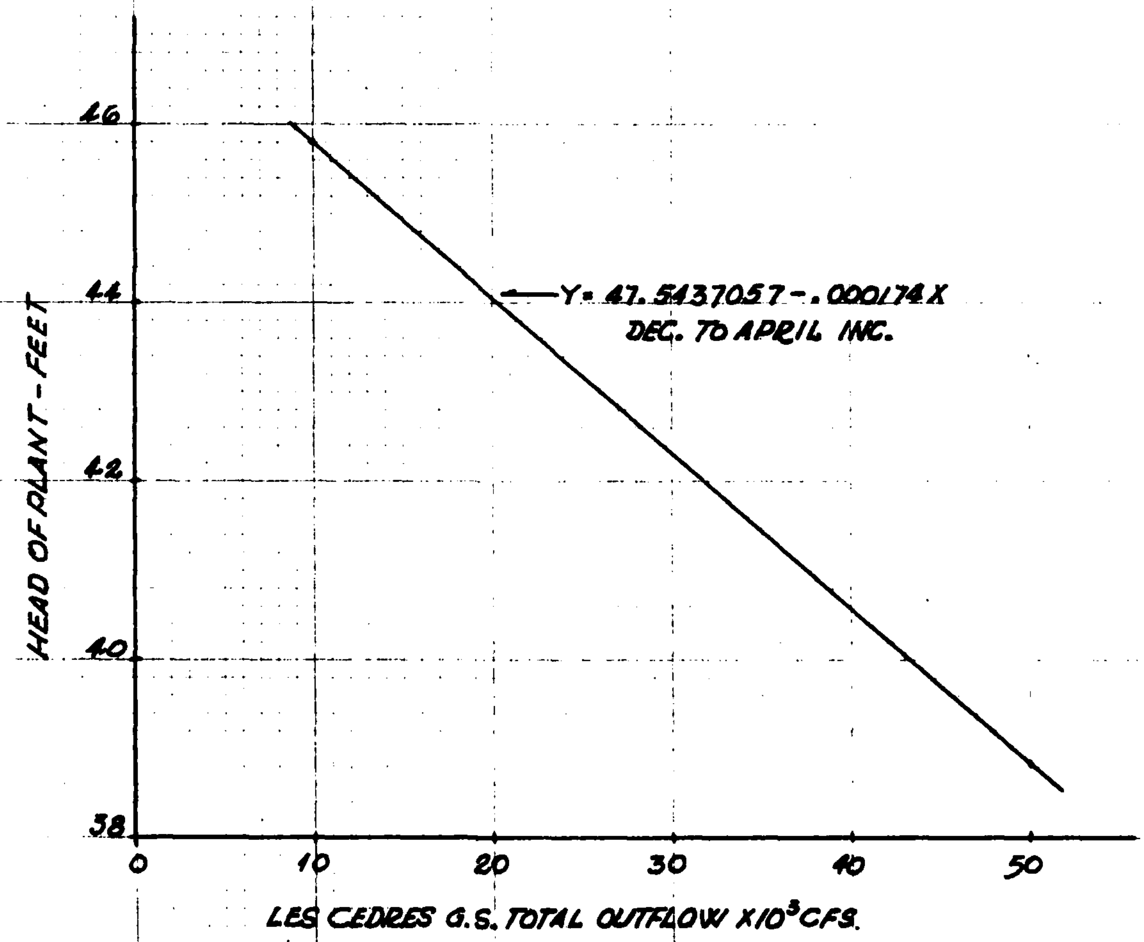


FIGURE E – 29

RELATIONSHIP BETWEEN TOTAL LES CEDRES OUTFLOW AND HEAD FOR DECEMBER TO APRIL INCLUSIVE

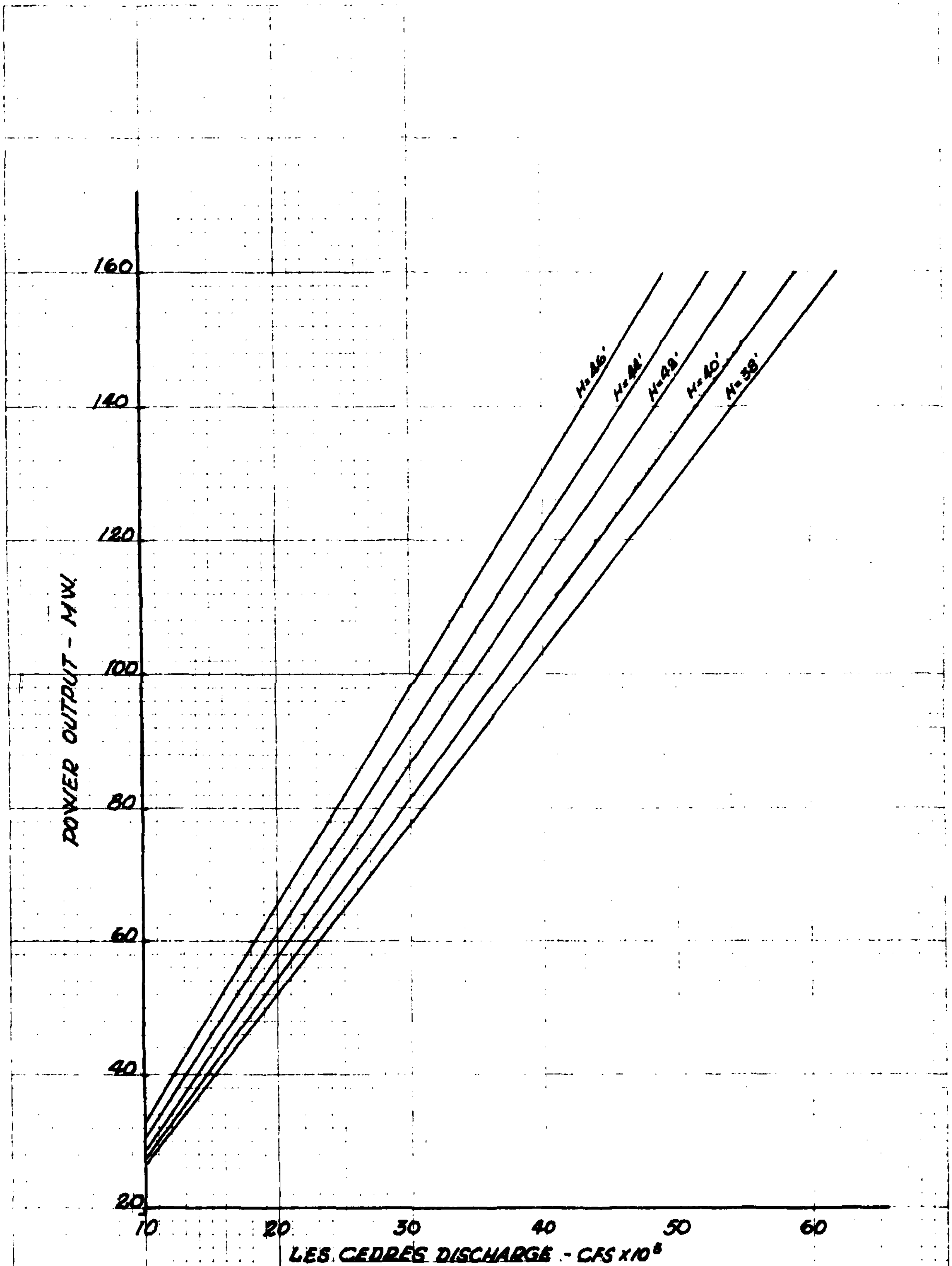


FIGURE E – 30

POWER OUTPUT - HEAD - DISCHARGE RELATIONSHIP FOR LES CEDRES

(5) The Beauharnois powerhouse tailwater elevation, from the Lake St. Louis stage-discharge relationship (Figure E-27);

(6) The gross head at Beauharnois powerhouse, obtained by subtracting the tailwater elevation from the forebay elevation;

(7) The gross head at Les Cedres plant, obtained from a relationship between Les Cedres total outflow and the gross head (Figure E-29); and

(8) Power output at the Beauharnois and Cedars plants, obtained by using the power-head-discharge for each plant (Figures E-28 and E-30).

Table E-6

Non-Power Flow Requirements At Beauharnois-Les Cedres Power Plants

Month	Navigation Requirements (cfs)	Other Requirements (cfs)*	Total (cfs)
January	0	2 500	2 500
February	0	2 500	2 500
March	200	2 600	2 800
April	500	2 600	3 100
May	600	2 600	3 200
June	700	2 600	3 300
July	700	2 600	3 300
August	700	2 600	3 300
September	600	2 600	3 200
October	600	2 600	3 200
November	600	2 600	3 200
December	400	2 500	2 900
Average Annual	470	2 575	3 045

*Municipal, industrial and recreational requirements

Table E-7

Maximum Permissible Discharge At Beauharnois
And Les Cedres Power Plants

Month	Beauharnois (cfs)	Les Cedres (cfs)
January	230,000	50,000
February	235,000	50,000
March	240,000	50,000
April	288,000	60,000
May	288,000	60,000
June	288,000	60,000
July	288,000	60,000
August	288,000	60,000
September	288,000	60,000
October	288,000	60,000
November	288,000	60,000
December	288,000	50,000
Annual Average	274,750	56,650

Section 6

DETERMINATION OF UNIT ENERGY AND CAPACITY VALUES

6.1 Basis of Evaluation

The Working Committee established an Ad-Hoc Economics Working Group to determine and recommend certain economic factors and criteria to serve as a common basis of evaluation for the International Lake Erie Regulation Study. In it's final report dated May 1978, this Working Group recommended the following criteria for evaluation purposes:

(1) An interest and discount rate of 8.5%
(2) A project economic life period for amortizing costs and discounting future benefits of 50 years beginnining 1985
(3) Price levels adjusted to 1979 costs
(4) The Canadian dollar considered at parity with the U.S. dollar
(5) Cost and benefit streams over time summarized in the following ways:

   (a) as a time profile of all costs and benefits in each year of occurrence over the project life

   (b) as a discounted present worth of each item in (a)

   (c) as a constant annuity with present values as calculated in (b)

6.2 Energy and Capacity Values

The energy and capacity values used for evaluating the effects of regulation plans on hydroelectric power generation were computed in accordance with the criteria listed in Subsection 6.1. These values together with an explanation of their determination are given for each power system in Subsections 6.2.1 through 6.2.4 and are summarized in Table E-8.

Table E-8

Average Annual Cost of Replacement Power Used for Evaluating Effects of Regulation Plans on Hydroelectric Power Generation

	Energy Values (mills per kWh)			Capacity Values ($ per kW/year)
	day	night	composite	
Upper Michigan			3.36	28.33
New York State			110.6	70.0
Ontario	17.24	12.12	15.53	33.08
Quebec			7.568	-

6.2.1 Ontario System

The projected unit energy and peak capacity values for the period 1985-2034 (50 years) are shown on Tables E-9 and E-10. The basis for the values is described below.

(1) Energy

(a) A recent calculated set of projected system values of incremental energy (mills/kWh was used as base). This established the day and night annual energy costs based on a recent escalation forecast (October, 1979) and a varying mix of fuels.

(b) These annual escalated energy costs (day and night) were converted to July, 1979, price levels by deflating using an Implicit Price Deflator based on Gross National Product, ("Economic Outlook", Long Form, September 1979, Table E-11).

(c) Application of these deflated energy costs (mills/kWh) to the annual energy differences (GWh) of each alternative for the 50-year period starting in 1985 provided the annual costs.

(d) The annual costs were discounted (brought to present worth) to 1985 using an annual discount rate of 8.5%.

(e) These annual costs were summed up and amortized over 50 years by dividing by 11.5656 to yield an average annual cost of replacement power.

(2) Peak

(a) The December peak outputs for each alternative were converted to a mean value and a standard deviation.

(b) These were used to calculate a statistical change in Load Meeting Capability (LMC) for each alternative.

(c) The cost per LMC kilowatt at 1979 price levels is $692. This value was based on capital costs of plant, incorporation, fixed operation and maintenance (O&M) and associated reserve generating capacity.

The value of $692/kW represents a plant having a 30-year life and is equivalent to an annuity of $59/kW at 8.5% interest rate. Since in some studies the LMC kilowatts may vary from year to year, this annual value will be more suitable for calculations. This has the added benefit of avoiding the need for residual value calculations.

The $59/kW is made up of $49/kW for capital related items and $10/kW for the annual O&M. The year 1994 is currently the earliest in which new generating capacity is expected to be added to the system and therefore, is the first in which a change in system capacity should be penalized at the value of $59/kW. However, there will be some 'mothballed' generation in 1985 and later years up to 1993. Any change in the amount of this

Table E-9

Ontario System

Projected Unit Energy Values 1985 - 2034 (50 Years)

Year	Escalated Values (mills/kWh) Day	Escalated Values (mills/kWh) Night	Deflation Factor to 1979	Deflated Values (mills/kWh) Day	Deflated Values (mills/kWh) Night	1985 Present Worth Factor*	1985 Present Worth (mills/kWh) Day	1985 Present Worth (mills/kWh) Night
1985	23.2	19.6	0.6468	15.0	12.7	0.9217	13.8	11.7
86	25.0	21.1	0.6017	15.0	12.7	0.8495	12.7	10.8
87	27.1	22.7	0.5597	15.2	12.7	0.7829	11.9	9.9
88	29.2	24.3	0.5256	15.3	12.8	0.7216	11.0	9.2
89	31.1	25.6	0.4958	15.4	12.7	0.6650	10.2	8.4
1990	33.2	27.0	0.4678	15.5	12.6	0.6129	9.5	7.7
91	36.7	28.6	0.4413	16.2	12.6	0.5649	9.2	7.1
92	40.6	30.3	0.4163	16.9	12.6	0.5207	8.8	6.6
93	44.9	32.3	0.3927	17.6	12.7	0.4799	8.4	6.1
94	49.1	33.9	0.3723	18.3	12.6	0.4423	8.1	5.6
1995	53.7	35.7	0.3529	19.0	12.6	0.4076	7.7	5.1
96	57.2	38.0	0.3345	19.1	12.7	0.3757	7.2	4.8
97	60.9	40.5	0.3170	19.3	12.8	0.3463	6.7	4.4
98	64.7	43.0	0.3005	19.4	12.9	0.3191	6.2	4.1
99	68.8	45.7	0.2862	19.7	13.1	0.2941	5.8	3.9
2000	73.0	48.5	0.2726	19.9	13.2	0.2711	5.4	3.6
01	76.4	50.0	0.2596	19.8	13.0	0.2499	4.9	3.2
02	79.9	51.6	0.2472	19.8	12.8	0.2303	4.6	2.9
03	83.7	53.1	0.2354	19.7	12.5	0.2122	4.2	2.7
04	87.5	54.7	0.2242	19.6	12.3	0.1956	3.8	2.4
2005	91.6	56.2	0.2136	19.6	12.0	0.1803	3.5	2.2
06	95.8	57.8	0.2034	19.5	11.8	0.1662	3.2	2.0
07	100.2	59.3	0.1937	19.4	11.5	0.1531	3.0	1.8
08	104.8	60.9	0.1845	19.3	11.2	0.1412	2.7	1.6
09	109.5	62.4	0.1757	19.2	11.0	0.1301	2.5	1.4

Table E-9 (Cont'd)

Ontario System

Projected Unit Energy Values 1985 - 2034 (50 Years)

Year	Escalated Values Day (mills/kWh)	Escalated Values Night (mills/kWh)	Deflation Factor to 1979	Deflated Values Day (mills/kWh)	Deflated Values Night (mills/kWh)	1985 Present Worth Factor*	1985 Present Worth Day (mills/kWh)	1985 Present Worth Night (mills/kWh)
2010	114.5	63.9	0.1673	19.2	10.7	0.1199	2.3	1.3
11	119.7	65.3	0.1594	19.1	10.4	0.1105	2.1	1.1
12	125.1	66.7	0.1518	19.0	10.1	0.1019	1.9	1.0
13	130.7	68.1	0.1445	18.9	9.8	0.0939	1.8	0.92
14	136.5	69.4	0.1377	18.8	9.6	0.0865	1.6	0.83
2015	142.6	70.6	0.1311	18.7	9.3	0.0797	1.5	0.74
16	148.9	71.7	0.1249	18.6	9.0	0.0735	1.4	0.66
17	155.5	72.7	0.1189	18.5	8.6	0.0677	1.2	0.58
18	162.4	73.6	0.1133	18.4	8.3	0.0624	1.1	0.52
19	169.5	74.4	0.1079	18.3	8.0	0.0575	1.1	0.46
2020	176.8	75.0	0.1027	18.2	7.7	0.0530	0.96	0.41
21	184.5	75.4	0.0978	18.0	7.4	0.0489	0.88	0.36
22	192.5	75.7	0.0932	17.9	7.1	0.0450	0.81	0.32
23	200.7	75.7	0.0887	17.8	6.7	0.0415	0.74	0.28
24	209.3	75.4	0.0845	17.7	6.4	0.0383	0.68	0.25
2025	218.2	74.9	0.0805	17.6	6.0	0.0353	0.62	0.21
26	227.4	74.1	0.0767	17.4	5.7	0.0325	0.57	0.19
27	236.9	72.9	0.0730	17.3	5.3	0.0300	0.52	0.16
28	246.8	71.3	0.0695	17.2	5.0	0.0276	0.47	0.14
29	257.0	69.4	0.0662	17.0	4.6	0.0254	0.43	0.12
2030	267.6	66.9	0.0631	16.9	4.2	0.0235	0.40	0.10
31	282.8	70.6	0.0600	17.0	4.2	0.0216	0.37	0.09
32	299.0	74.5	0.0572	17.1	4.3	0.0199	0.34	0.09
33	316.0	78.6	0.0545	17.2	4.3	0.0184	0.32	0.08
34	334.0	82.9	0.0519	17.3	4.3	0.0170	0.29	0.07
				Total		11.5656	199.40	140.18

*Discount Rate 8.5%

Table E-10

Ontario System

Projected Unit Peak Capacity Values 1985 - 2034 (50 Years)

Year	July 1979 Annual Value ($/kW)	1985 Present Worth Factor*	1985 Present Worth Factor ($/kW)	Year	July 1979 Annual Value ($/kW)	1985 Present Worth Factor*	1985 Present Worth Factor ($/kW)
1985	10	0.9217	9.217	2010	59	0.1199	7.074
86	10	0.8495	8.495	11	59	0.1105	6.520
87	10	0.7829	7.829	12	59	0.1019	6.012
88	10	0.7216	7.216	13	59	0.0939	5.540
89	10	0.6650	6.650	14	59	0.0865	5.104
1990	10	0.6129	6.129	2015	59	0.0797	4.702
91	10	0.5649	5.649	16	59	0.0735	4.337
92	10	0.5207	5.207	17	59	0.0677	3.994
93	10	0.4799	4.799	18	59	0.0624	3.682
94	59	0.4423	26.096	19	59	0.0575	3.393
1995	59	0.4076	24.048	2020	59	0.0530	3.127
96	59	0.3757	22.166	21	59	0.0489	2.885
97	59	0.3463	20.432	22	59	0.0450	2.655
98	59	0.3191	18.827	23	59	0.0415	2.449
99	59	0.2941	17.352	24	59	0.0383	2.260
2000	59	0.2711	15.995	2025	59	0.0353	2.083
01	59	0.2499	14.744	26	59	0.0325	1.918
02	59	0.2303	13.588	27	59	0.0300	1.770
03	59	0.2122	12.520	28	59	0.0276	1.628
04	59	0.1956	11.540	29	59	0.0254	1.499
2005	59	0.1803	10.638	2030	59	0.0235	1.387
06	59	0.1662	9.806	31	59	0.0216	1.274
07	59	0.1531	9.033	32	59	0.0199	1.174
08	59	0.1412	8.331	33	59	0.0184	1.086
09	59	0.1301	7.676	34	59	0.0170	1.003
				Total		11.5656	382.539

*Discount Rate 8.5%

Table E-11

Inflation Forecast - Canada

(% change)

Date	Consumer Price Index	Implicit Price Deflator	Industry Selling Price Index
1979	9.0	8.5	12.5
1980	9.0	8.7	9.0
1981	7.5	7.5	8.0
1982	7.0	6.5	8.5
1983	7.5	8.0	9.0
1984	7.0	7.5	8.0
1985	6.5	7.0	8.0
1986	7.5	7.5	9.0
1987	7.5	7.5	8.5
1988	6.5	6.5	5.5
1989-1993	6.0	6.0	6.0
1994-1998	5.5	5.5	5.5
1999-2018	5.0	5.0	5.0

Source: Economics Division, Ontario Hydro

generation will cause a corresponding change in O&M costs. For this reason the $10/kW O&M charge was applied each year from 1985 to 1993.

(d) For each alternative, the value of $59/kW per annum was applied as appropriate to the December change in LMC in each year of the 50-year study period starting in 1985.

These annual values were then treated in similar fashion to the energy calculations above.

6.2.2 Quebec System

Ice conditions limit the flow at the time that the Hydro Quebec system experiences peak load; therefore no peak capacity benefit or loss is expected and only the effects of regulation on energy production were evaluated.

(1) Energy

(a) Dynamic marginal values of energy were assumed to be those of hydroelectric energy replacement from 1985 up to 1995 and those of nuclear energy replacement after 1995. These values are shown in column 2 of table E-12. They represent the yearly cost in current dollars for replacing 1 MWh in non-peaking hours.

(b) The deflation factor was calculated by assuming an index of 1.00 for 1979 and a fixed inflation rate of 10% between 1979 and 1981 and a projected inflation rate from 1982-2034 as tabulated below:

Year	Inflation rate - %
1982-1985	10.0
1986-1987	7.1
1988-1989	6.0
1990-2034	5.7

The deflation factor is shown in column 3 of table E-12. To obtain the dynamic marginal value of energy in constant 1979 dollars, (Column 4), each value in column 2 was divided by its respective deflation factor.

(c) Column 5 shows the present worth factor based on an annual discount rate of 8.5%, taken from the following equation .

$$P = F \times A$$

where P = the present worth of A, referring to 1985;
A = the annual value of energy as given in column 4
F = the interest factor, which is given by the following equation

Table E-12

Quebec System

Projected Unit Energy Values 1985-2034 (50 Years)

Year	Escalated Value Current $ mills/kWh	Deflation Factor to 1979	1979 Value mills/kWh	1985 Present Worth Factor*	1985 Present Worth mills/kWh	Year	Escalated Value Current $ mills/kWh	Deflation Factor to 1979	1979 Value mills/kWh	1985 Present Worth Factor*	1985 Present Worth mills/kWh
1	2	3	4	5	6	1	2	3	4	5	6
1985	0.0	1.602	0.0	0.9217	0.0	2010	62.58	6.629	9.44	0.1199	1.132
86	9.40	1.716	5.48	0.8495	4.653	11	66.15	7.007	9.44	0.1105	1.043
87	10.00	1.838	5.44	0.7829	4.260	12	69.92	7.406	9.44	0.1019	0.962
88	13.26	1.948	6.81	0.7216	4.912	13	73.90	7.828	9.44	0.0939	0.886
89	14.91	2.065	7.22	0.6650	4.802	14	78.12	8.275	9.44	0.0865	0.817
1990	17.47	2.189	7.98	0.6129	4.892	2015	82.57	8.746	9.44	0.0797	0.753
91	18.62	2.314	8.05	0.5649	4.546	16	87.28	9.245	9.44	0.0735	0.694
92	17.70	2.446	7.24	0.5207	3.768	17	92.25	9.772	9.44	0.0677	0.639
93	20.82	2.585	8.05	0.4799	3.865	18	97.51	10.329	9.44	0.0624	0.589
94	23.49	2.732	8.60	0.4423	3.803	19	103.07	10.917	9.44	0.0575	0.543
1995	28.51	2.888	9.87	0.4076	4.024	2020	108.94	11.540	9.44	0.0530	0.501
96	30.95	3.051	10.14	0.3757	3.811	21	115.15	12.197	9.44	0.0489	0.461
97	32.14	3.224	9.97	0.3463	3.452	22	121.72	12.893	9.44	0.0450	0.425
98	33.45	3.408	9.82	0.3191	3.132	23	128.65	13.628	9.44	0.0415	0.392
99	34.57	3.602	9.60	0.2941	2.823	24	135.99	14.405	9.44	0.0383	0.361
2000	35.95	3.808	9.44	0.2711	2.559	2025	143.74	15.226	9.44	0.0353	0.333
01	38.00	4.025	9.44	0.2499	2.359	26	151.93	16.094	9.44	0.0325	0.307
02	40.17	4.254	9.44	0.2303	2.175	27	160.59	17.011	9.44	0.0300	0.283
03	42.45	4.497	9.44	0.2122	2.004	28	169.75	17.980	9.44	0.0276	0.261
04	44.87	4.753	9.44	0.1956	1.847	29	179.42	19.006	9.44	0.0254	0.240
2005	47.43	5.024	9.44	0.1803	1.702	2030	189.65	20.089	9.44	0.0235	0.221
06	30.14	5.311	9.44	0.1662	1.569	31	200.46	21.234	9.44	0.0216	0.204
07	52.99	5.613	9.44	0.1531	1.446	32	211.88	22.444	9.44	0.0199	0.188
08	56.01	5.933	9.44	0.1412	1.333	33	223.96	23.723	9.44	0.0184	0.173
09	59.21	6.272	9.44	0.1301	1.228	34	236.73	25.075	9.44	0.0170	0.160

* Discount Rate 8.5%

$$F = \frac{1}{(1+i)^n}$$

where i = discount rate (8.5%)

n = the year, starting with 1985

(d) Column 6 gives the 1985 present worth marginal values of 1 kWh of replacement energy in non-peaking hours in constant 1979 mills for each of the 50 years of the project's economic life. The theoretical annual amortized value (annuity) of replacing 1 kWh is given by the following equation:

$$a = \frac{\Sigma_1^n P}{\Sigma_1^n F}$$

$$= \frac{87.533}{11.566}$$

$$= 7.568 \text{ mills/kWh}$$

Where P and F are defined above

This value was multiplied by the difference in average energy output, over the 50-year project economic life to obtain the annual amortized value of energy. The total present worth value was obtained by multiplying the annual amortized value by F. (F = 11.566).

6.2.3 New York State System

For a given regulation plan changes to energy production or capacity were evaluated compared to the basis-of-comparison for the plant at Niagara. This method was used because; the changes in plan flow from basis-of-comparison are small and deemed to be minor; the plant efficiency is essentially linear throughout the range of diversion capacity used in this study; and virtually all available water can be diverted in the various cases; thus the study lends itself to evaluation of difference in losses for energy.

At the St. Lawrence River plant the procedures were similar to Ontario Hydro since the Saunders and Moses plants are essentially equivalent. Thus the energy and peak capacities were those which would result from the same supplied and diversions as the past but with levels and flows indicated by the rules of a given regulation plan.

These methods were developed to determine the economic benefit or loss which would result from implementing each of the regulation plans compared to the basis of comparison. Thus the evaluation is based upon the change in value of energy and capacity which is associated with such regulation.

(1) Energy

A review was made of existing and future generation units expected to be in service to supply the New York power system (New York Power Pool (NYPP)) beyond 1985. From experience and judgment it is most likely that any displacement of hydropower in the amounts envisioned in this study would be made up by oil-fired generation. In recent years New York, and New England as well, have become heavily dependent on oil as compared to the rest of the United States. This has happened because environmental rules based on public concerns have caused a shift to exclusive low-sulfur oil fired generation in the heavily populated lower New York - Long Island areas which have over half the load in the state. There are no cheaper coal fired units to service these areas. It is currently state policy to build no more nuclear units and the existing 5 units are base loaded.

Thus, since the state is serviced by one interconnected grid and exchanges between neighbouring systems are constrained by transmission limitations, it has come about that incremental loads in New York normally receive energy from oil-fired steam or gas-turbine units. Thus any reduction in hydro-generation would be replaced by generation from oil-fired sources.

The total water available to the system is the same in each of the regulation plans being studied. At the Niagara plant, each plan was reviewed on a monthly basis to determine the percent of time the available flows could not be diverted because the diversion capability was exceeded. This amount was compared with the basis-of-comparison and the difference determined. The Niagara plant unit efficiency of 22 kW/cfs determined the energy involved and was assessed at the projected future cost of oil generation as shown in Table.

At the St. Lawrence Moses plant, the differences in average annual energy for each plan were the same as those ascribed to the Saunders plant. These energy differences were then given economic values based on oil-fired generation as described below.

There are numerous projections on the future cost of oil but none that extend more than about 10 years into the future. However, this study extends 50 years beyond 1985. Future world events and their effects on market conditions for oil are, of course, virtually impossible to predict, and yet the events of the past decade seem to forbode an escalation of oil costs, beyond inflation, well into the forseeable future. After much discussion and on the advice of the Ad Hoc Economic Working Group it was decided that a middle course be adopted.

Specifically the forecast model for real oil costs assume a 5% increase per year, in excess of normal inflation from the present for the first 20 years into the study period; that is to the year 2005. The next 30 years were simply too difficult to predict, so only inflation factors were deemed to apply. Thus the annual value of 50 mill/kWh energy in 1979

over a 50 year project life from 1985 to 2034 at 8 1/2% annual interest is 110.6 mills/kWh in terms of present dollars.

(2) Peak

Changes in the installed capacity that would occur due to each of the plans are small. Normally the integrated electrical system operates with a reserve of 20% or more. For purposes of this study to determine public costs from any change in hydro capacity it was assumed that the reserve requirements for good operating practice would be the same for any condition.

Any planned future construction is assumed to meet future loads and would not be available to meet any diminishing of existing capacity. Thus, any loss in existing capacity would have to be replaced with new construction or capacity purchased from a neighbouring system. In these studies there were capacity losses due to lower flows during a limited percentage of time. It was assumed therefore, that any capacity loss would be purchased using prevailing market conditions. At prevailing 1979 rates, costs for 1985 and beyond would be equivalent to $70/kW/year at assumed commercial costs and interest rates approximating 10%. (It is noted here that while PASNY is a "public" authority, the other NYPP members are private corporations as are the majority of companies in neighbouring pools. Therefore a private rather than public cost of borrowing money is assumed.)

6.2.4 Upper Michigan System

Generating facilities owned or controlled by Edison Sault Electric Company are insufficient to meet the needs of the area served and the Company purchases power from Consumers Power Company with which it is interconnected. Evaluations of regulation plans were on the basis that the difference in power production by the existing hydroelectric power plants on the United States side of the St. Marys River, between any regulation plan and the basis-of-comparison, would be identical to the difference in power purchases from Consumers Power Company.

(1) Energy and Peak

A constant value of 3.36 mills/kWh for energy and $28.33/kW/year for peak was assumed throughout the study period.

Section 7

EVALUATION of REGULATION PLANS

7.1 General

This section presents the results of the detailed economic evaluations, made by the Power subcommittee, of Lake Erie regulation plans 25N, 15S and 6L, with Lake Ontario regulation Categories 1, 2 and 3. Each plan was evaluated according to the methodology described in Sections 2 through to 6 using the basis-of-comparison as described in Subsection 1.3. In addition, for Category 3 Lake Ontario regulation, each Lake Erie plan was evaluated against an adjusted basis-of-comparison. The adjusted basis-of-comparison assumed increased St. Lawrence River channel capacities that would permit the present Lake Ontario Orders of Approval to be met with the high supplies of the mid-1970's. This eliminated the power benefits that would be achieved by meeting the Orders of Approval on Lake Ontario from the effect of limited regulation of Lake Erie.

7.2 Adjustment to Energy Benefits

Under the sequence of supply (1900-1976) assumed for these studies, the levels of each of the lakes at the end of the period (December 1976) were slightly lower under regulation than under the basis-of-comparison. Consequently, the corresponding long-term mean outflows were greater by varying amounts, up to about 400 cfs.

A sensititivity analysis indicated that this anomaly impacted on the results of the study, and therefore an adjustment was made to the computed average annual energy benefits at each generating station. The details of the adjustments to the average annual energy benefits/losses are explained and tabulated in Annex C which also includes tabulations of the unadjusted energy outputs, and the peak outputs.

7.3 Results of Evaluation

The benefits/losses in peak load meeting capability and the adjusted benefits/losses in average annual energy production are summarized for each category on Tables E-13 to 16. The corresponding annual amortized values and present worth values are summarized on Tables E-17 to 20.

7.3.1 Category 1

The evaluations of Plans 25N, 15S and 6L are shown on Tables E-13 and E17. Table E-13 shows the difference in average annual energy in GWh and the difference in peak load meeting capability in MW. Table E-17 shows the annual amortized value of the energy and peak differences and the combined present worth values.

Plan 25N - The net annual effect on power generation would be a loss of $2,476,000 having a present worth value of $28,6[illegible]6,000. In Canada, the average annual loss would be 71.3 GWh of energy and 0.8 MW of peak which

Table E-13

Power Evaluation - Category 1

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Difference in Average Annual Energy Production
and
Peak Load Meeting Capability

	Difference from BOC					
	Average Annual Energy (GWh)			Peak Capacity (MW)		
	25N	15S	6L	25N	15S	6L
Ontario						
St. Marys	+ 2.2	+ 1.4	+ 0.3			
Niagara	-61.1	-68.3	-23.3			
St. Lawrence	- 5.1	+ 0.5	- 1.1			
Total	-64.0	-66.4	-24.1	- 0.8	+0.22	+0.76
Quebec						
St. Lawrence	- 7.3	- 5.2	- 2.6			
Total Canada	-71.3	-71.6	-26.7	- 0.8	+0.22	+0.76
New York State						
Niagara	- 0.7	- 2.5	- 1.1	- 9.0	-1.3	-0.4
St. Lawrence	- 5.1	+ 0.5	- 1.1	- 1.4	+0.2	+0.2
Total	- 5.8	- 2.0	- 2.2	-10.4	-1.1	-0.2
Upper Michigan	+ 2.0	+ 1.7	+ 0.2	+ 0.06	+0.02	+0.01
Total U.S.	- 3.8	- 0.3	- 2.0	-10.34	-1.08	-0.19
Total U.S. and Canada	-75.1	-71.9	-28.7	-11.14	-0.86	+0.57

Table E-14

Power Evaluation - Category 2

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Difference in Average Annual Energy Production
and
Peak Load Meeting Capability

	Difference from BOC					
	Average Annual Energy (GWh)			Peak Capacity (MW)		
	25N	15S	6L	25N	15S	6L
Ontario						
St. Marys	+ 2.2	+ 1.4	+ 0.3			
Niagara	-63.0	-69.2	-23.8			
St. Lawrence	+ 3.0	+ 5.8	+ 3.8			
Total	-57.8	-62.0	-19.7	- 4.45	-2.92	-2.37
Quebec						
St. Lawrence	- 4.7	- 2.3	+ 1.2			
Total Canada	-62.5	-64.3	-18.5	- 4.45	-2.92	-2.37
New York State						
Niagara	- 0.7	- 2.5	- 1.1	- 9.0	-1.3	-0.4
St. Lawrence	+ 3.0	+ 5.8	+ 3.8	- 0.9	+0.1	+0.2
Total	+ 2.3	+ 3.3	+ 2.7	- 9.9	-1.2	-0.2
Upper Michigan	+ 2.0	+ 1.7	+ 0.2	+ 0.06	+0.02	+0.01
Total U.S.	+ 4.3	+ 5.0	+ 2.9	- 9.84	-1.18	-0.19
Total U.S. and Canada	-58.2	-59.3	-15.6	-14.29	-4.10	-2.56

Table E-15

Power Evaluation - Category 3

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Difference in Average Annual Energy Production
and
Peak Load Meeting Capability

	Difference from BOC					
	Average Annual Energy (GWh)			Peak Capacity (MW)		
	25N	15S	6L	25N	15S	6L
Ontario						
St. Marys	+ 2.2	+ 1.4	+ 0.3			
Niagara	-63.1	-67.7	-23.0			
St. Lawrence	+ 2.3	+ 8.8	+ 4.0			
Total	-58.6	-57.5	-18.7	- 2.43	-3.06	-5.57
Quebec						
St. Lawrence	-17.5	-14.8	- 9.3			
Total Canada	-76.1	-72.3	-28.0	- 2.43	-3.06	-5.57
New York State						
Niagara	- 0.7	- 2.5	- 1.1	- 9.0	-1.3	-0.4
St. Lawrence	+ 2.3	+ 8.8	+ 4.0	- 0.59	+0.83	+0.41
Total	+ 1.6	+ 6.3	+ 2.9	- 9.59	-0.47	+0.01
Upper Michigan	+ 2.0	+ 1.7	+ 0.2	+ 0.06	+0.02	+0.01
Total U.S.	+ 3.6	+ 8.0	+ 3.1	- 9.53	-0.45	+0.02
Total U.S. and Canada	-72.5	-64.3	-24.9	-11.96	-3.51	-5.55

Table E-16

Power Evaluation - Category 3

Regulation Plans 25N, 15S and 6L Compared to Adjusted Basis-of-Comparison (ABOC)

Difference in Average Annual Energy Production
and
Peak Load Meeting Capability

	Difference from ABOC					
	Average Annual Energy (GWh)			Peak Capacity (MW)		
	25N	15S	6L	25N	15S	6L
Ontario						
St. Marys	+ 2.2	+ 1.4	+ 0.3			
Niagara	-63.1	-67.7	-23.0			
St. Lawrence	- 1.8	+ 4.7	- 0.1			
Total	-62.7	-61.6	-22.8	+ 0.45	-0.17	-2.68
Quebec						
St. Lawrence	-10.3	- 7.7	- 2.1			
Total Canada	-73.0	-69.3	-24.9	+ 0.45	-0.17	-2.68
New York State						
Niagara	- 0.7	- 2.5	- 1.1	- 9.0	-1.3	-0.4
St. Lawrence	- 1.8	+ 4.7	- 0.1	- 1.0	+0.42	0.0
Total	- 2.5	+ 2.2	- 1.2	-10.0	-0.88	-0.4
Upper Michigan	+ 2.0	+ 1.7	+ 0.2	+ 0.06	+0.02	+0.01
Total U.S.	- 0.5	+ 3.9	- 1.0	- 9.94	-0.86	-0.39
Total U.S. and Canada	-73.5	-65.4	-25.9	- 9.49	-1.03	-3.07

Table E-17

Power Evaluation - Category 1

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Annual Amortized and Present Worth of Difference

in

Average Annual Energy and Peak Load Meeting Capability

	Annual Amortized Value ($1000)									Present Worth of Total ($1000)		
	Energy			Peak			Total					
	25N	15S	6L	25N	15S	6L	25N	15S	6L	25N	15S	6L
Ontario												
St. Marys	+ 34	+ 22	+ 5									
Niagara	- 964	-1,277	-459									
St. Lawrence	- 105	+ 3	- 19									
Total	-1,035	-1,252	-473	- 26	+ 7	+ 25	-1,061	-1,245	-448	-12,271	-14,399	-5,181
Quebec												
St. Lawrence	- 55	- 39	- 20				- 55	- 39	- 20	- 636	- 451	- 231
Total Canada	-1,090	-1,291	-493	- 26	+ 7	+ 25	-1,116	-1,284	-468	-12,907	-14,850	-5,412
New York State												
Niagara	- 77	- 276	-122	-630	- 91	- 28						
St. Lawrence	- 564	+ 55	-122	- 98	+ 14	+ 14						
Total	- 641	- 221	-244	-728	- 77	- 14	-1,369	- 298	-258	-15,833	- 3,447	-2,984
Upper Michigan	+ 7	+ 6	+ 1	+ 2	+ 1	0	+ 9	+ 7	+ 1	+ 104	+ 81	+ 12
Total U.S.	- 634	- 215	-243	-726	- 76	- 14	-1,360	- 291	-257	-15,729	- 3,366	-2,972
Total U.S. and Canada	-1,724	-1,506	-736	-752	- 69	+ 11	-2,476	-1,575	-725	-28,636	-18,216	-8,384

Table E-18

Power Evaluation - Category 2

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Annual Amortized and Present Worth of Difference

in

Average Annual Energy and Peak Load Meeting Capability

	Annual Amortized Value ($1000)									Present Worth of Total ($1000)		
	Energy			Peak			Total					
	25N	15S	6L	25N	15S	6L	25N	15S	6L	25N	15S	6L
Ontario												
St. Marys	+ 34	+ 22	+ 5									
Niagara	-993	-1,290	-466									
St. Lawrence	+ 16	+ 81	+ 54									
Total	-943	-1,187	-407	-147	- 97	- 78	-1,090	-1,284	-485	-12,606	-14,850	-5,609
Quebec												
St. Lawrence	- 36	- 17	+ 9				- 36	- 17	+ 9	- 416	- 197	+ 104
Total Canada	-979	-1,204	-398	-147	- 97	- 78	-1,126	-1,301	-476	-13,022	-15,047	-5,505
New York State												
Niagara	- 77	- 276	-122	-630	- 91	- 28						
St. Lawrence	+332	+ 641	+420	- 63	+ 7	+ 14						
Total	+255	+ 365	+298	-693	- 84	- 14	- 438	+ 281	+284	- 5,066	+ 3,250	+3,285
Upper Michigan	+ 7	+ 6	+ 1	+ 2	+ 1	0	+ 9	+ 7	+ 1	+ 104	+ 81	+ 12
Total U.S.	+262	+ 371	+299	-691	- 83	- 14	- 429	+ 288	+285	- 4,962	+ 3,331	+3,297
Total U.S. and Canada	-717	- 833	- 99	-838	-180	- 92	-1,555	-1,013	-191	-17,984	-11,716	-2,208

Table E-19

Power Evaluation - Category 3

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Annual Amortized and Present Worth of Difference

in

Average Annual Energy and Peak Load Meeting Capability

	Annual Amortized Value ($1000)									Present Worth of Total ($1000)		
	Energy			Peak			Total					
	25N	15S	6L	25N	15S	6L	25N	15S	6L	25N	15S	6L
Ontario												
St. Marys	+ 34	+ 22	+ 5									
Niagara	- 995	-1,268	-454									
St. Lawrence	+ 11	+ 135	+ 62									
Total	- 950	-1,111	-387	- 80	-101	-184	-1,030	-1,212	-571	-11,912	-14,017	-6,604
Quebec												
St. Lawrence	- 132	- 112	- 70				- 132	- 112	- 70	- 1,527	- 1,295	- 810
Total Canada	-1,082	-1,223	-457	- 80	-101	-184	-1,162	-1,324	-641	-13,439	-15,312	-7,414
New York State												
Niagara	- 77	- 276	-122	-630	- 91	- 28						
St. Lawrence	+ 254	+ 973	+442	- 41	+ 58	+ 29						
Total	+ 177	+ 697	+320	-671	- 33	+ 1	- 494	+ 664	+321	- 5,713	+ 7,680	+3,712
Upper Michigan	+ 7	+ 6	+ 1	+ 2	+ 1	0	+ 9	+ 7	+ 1	+ 104	+ 81	+ 12
Total U.S.	+ 184	+ 703	+321	-669	- 32	+ 1	- 485	+ 671	+322	- 5,609	+ 7,761	+ 3,724
Total U.S. and Canada	- 898	- 520	-136	-749	-133	-183	-1,647	- 653	-319	-19,048	- 7,551	-3,690

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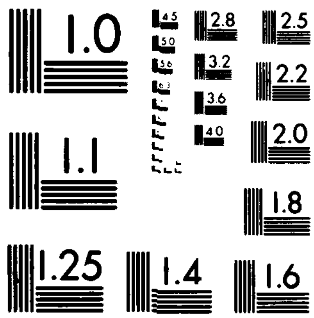

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Table E-20

Power Evaluation - Category 3

Regulation Plans 25N, 15S and 6L Compared to Adjusted Basis-of-Comparison (ABOC)

Annual Amortized and Present Worth of Difference

in

Average Annual Energy and Peak Load Meeting Capability

	Annual Amortized Value ($1000)									Present Worth of Total ($1000)		
	Energy			Peak			Total					
	25N	15S	6L	25N	15S	6L	25N	15S	6L	25N	15S	6L
Ontario												
St. Marys	+ 34	+ 22	+ 5									
Niagara	- 995	-1,268	-454									
St. Lawrence	- 53	+ 70	- 2									
Total	-1,014	-1,176	-451	+ 15	- 6	- 89	- 999	-1,182	-540	-11,554	-13,671	-6,245
Quebec												
St. Lawrence	- 78	- 58	- 16				- 78	- 58	- 16	- 902	- 671	- 185
Total Canada	-1,092	-1,234	-467	+ 15	- 6	- 89	-1,077	-1,240	-556	-12,456	-14,342	-6,430
New York State												
Niagara	- 77	- 276	-122	-630	-91	- 28						
St. Lawrence	- 199	+ 520	- 11	- 70	+29	0						
Total	- 276	+ 244	-133	-700	-62	- 28	- 976	+ 182	-161	-11,288	+ 2,104	-1,862
Upper Michigan	+ 7	+ 6	+ 1	+ 2	+ 1	0	+ 9	+ 7	+ 1	+ 104	+ 81	+ 12
Total U.S.	- 269	+ 250	-132	-698	-61	- 28	- 967	+ 189	-160	-11,184	+ 2,185	-1,850
Total U.S. and Canada	-1,361	- 984	-599	-683	-67	-117	-2,044	-1,051	-716	-23,640	-12,157	-8,280

has a combined annual value of $1,116,000. In the U.S., the loss would be 3.8 GWh of energy and 10.34 MW of peak which has a combined annual value of $1,360,000.

Plan 15S - The net annual effect on power generation would be a loss of $1,575,000 having a present worth value of $18,216,000. In Canada, there would be a loss of 71.6 GWh of energy and a gain of 0.22 MW of peak resulting in a combined annual loss of $1,284,000. In the U.S., the loss would be 0.3 GWh of energy and 1.08 MW of peak with an annual value of $291,000.

Plan 6L - The net annual loss to power would be $725,000 with a present worth value of $8,384,000. In Canada, there would be a loss of 26.7 GWh of energy and a gain of 0.76 MW of peak which gives a combined average annual loss of $468,000. In the U.S., there would be a loss of 2.0 GWh of energy and 0.19 MW of peak with a combined annual value of $257,000.

In summary, the three plans show net annual losses to power generation of 2.5, 1.6 and 0.7 million dollars for plans 25N, 15S and 6L respectively, which have present worth values of 28.6, 18.2 and 8.4 million dollars.

The following is a review of the effects of each regulation plan under Category 1 on each of the power systems involved.

7.3.1.1 Ontario System

Determination of energy outputs from the Ontario plants was made for each month of the period 1900-1976 assuming first the basis-of-comparison and then regulation Plans 25N, 15S and 6L under Category 1 in effect throughout the period. The average daytime and nighttime monthly energy outputs over the period were computed for the St. Marys River plant, for the Niagara area plants, and for the R.H. Saunders plant on the St. Lawrence River. The results (Tables E-13 and E-17) are summarized as follows:

Plan 25N would result in an annual loss of 64.0 GWh with an annual amortized value of $1,035,000. There would be a small gain at the St. Marys River plant (+2.2 GWh) and a small loss at the St. Lawrence (-5.1 GWh) but the bulk of the loss would occur at the Niagara plants. This loss is due to some of the additional water that is discharged from Lake Erie during high supply periods being wasted or used at the Cascade plants, which have a lower economy factor (kW/cfs) than the high head SAB plants.

Plan 15S would result in an annual loss of 66.4 GWh with an annual value of $1,252,000. Like Plan 25N, the major effect of Plan 15S occurs at the Niagara plants. The proportionally larger loss for 15S despite its lower discharge capacity is due to the operating constraints by which virtually all the additional water during the high supply period is discharged during tourist season nights and the non-tourist season when Niagara Falls flow requirement is 50,000 cfs.

Plan 6L would result in an annual loss of 24.1 GWh having an annual value of $473,000. Like the other two plans, the major effect of Plan 6L would occur at the Niagara plants. The proportionally larger losses from Plan 6L compared to Plan 25N would be due to operating constraints, similar to Plan 15S.

Determination of peak outputs from the Ontario plants was made for each month of the period, similar to the energy. The effect of the regulation plans on the total peak capacity from the St. Marys, Niagara and St. Lawrence River plants was analyzed and the difference in peak load meeting capability (Δ LMC) was determined from the December values. The results (Tables E-13 and E-17) are summarized as follows:

Plan 25N would result in a loss of 0.8 MW with an annual amortized value of $26,000. Plan 15S and 6L would result in gains of 0.22 MW and 0.76 MW respectively, with annual values of $7,000 and $25,000.

7.3.1.2 Quebec System

On the Quebec System the economic evaluation of the different plans under Category 1 compared to the basis-and-comparison show losses with annual amortized values and present worth vales (compounded over the 50 year economic life of the project) as follows:

	Value of Loss (-)	
Plan	Annual	Present Worth
25N	-$55,000	-$636,000
15S	-$39,000	-$451,000
6L	-$20,000	-$231,000

One can notice that the loss would increase in the same way as the increase of the discharge capacity of Lake Erie. The losses would be attributed to a different distribution of the flow coming from Lake Ontario, some of which has to be diverted from the Beauharnois Generating Station into the less productive Les Cedres Generating Station, due to limitation on the capacity of the Beauharnois plant.

7.3.1.3 New York State System

At the Niagara plant, each of the plans would result in annual energy losses as shown on Table E-13 varying from 2.5 GWh for Plan 15S to 0.7 GWh for Plan 25N. Adverse effects from Plans 15S and 6L are more severe at Niagara because the additional release of water from Lake Erie would occur at night and during the non-navigation season. At these times pursuant to the Niagara Treaty, the existing diversions for power are already the greatest. The U.S. share of these additional releases would thus exceed the diversion capacity of the Niagara Plant at the highest flows. Plan 25N has a greater monthly release capacity, so Lake Erie would not reach the extreme elevations of the other two plans with consequent diminishing of extreme outflows.

Effects on capacity at the Niagara plant, however, are most adverse with Plan 25N. Because the lower range of flows is lower than for the other plans. These results are also shown in Table E-13.

At the St. Lawrence plant, the greatest energy loss of 5.1 GWh would occur for Plan 25N (Table E-13). As in the case of the Saunders plant, losses are caused by the greater percentage of time that the forebay is lower compared to the basis-of-comparison due to higher discharges. Plan 6L would show a loss of 1.1 GWh annually while Plan 15S would show a small gain of 0.5 GWh on an annual basis.

Effects on capacity at St. Lawrence would be small for these plans.

The economic effects on power production overall showed that Plan 25N would be the most adverse with $1.37 million annual losses while Plan 6L was least severe with $0.26 million in annual losses. These are shown in Table E-17.

7.3.1.4 Upper Michigan System

Under Category 1, all the Lake Erie regulation plans evaluated would have beneficial effects on power generation at the U.S. power plants on the St. Marys River. The effect of Plan 25N (Table E-13 and E-17) would be an increase in energy of 2.0 GWh and a 0.06 MW increase in peak. This would give a combined annual benefit, under Plan 25N, of $9,000 and a present worth of $104,000. Plan 15S would have the effect of increasing energy by 1.7 GWh and peak by 0.02 MW, for a total annual benefit of $7,000 and present worth of $81,000. Likewise, Plan 6L would increase energy and peak by 0.2 GWh and 0.01 MW, respectively, for a combined annual benefit of $1,000 and present worth of $12,000.

These net increases would be due to the backwater effects of Lake Erie regulation on the levels of Lakes Michigan-Huron, and thus on Lake Superior; which in turn affect the headwater and tailwater levels of the power plants.

7.3.2 Category 2

The peak and energy differences associated with Category 2 are shown on Tables E-14 and the corresponding monetary values are shown on Table E-18.

Plan 25N - The net annual effect on power generation would be a loss of $1,555,000 which has a present worth value of $17,984,000. In Canada, the loss would be 62.5 GWh of energy and 4.45 MW of peak which has a combined annual value of $1,126,000. In the U.S., there would be a gain of 4.3 GWh of energy and a loss of 9.84 MW of peak. The annual value would be a gain of $262,000 and a loss of $691,000 giving a combined net loss of $429,000.

Plan 15S - The net annual effect on power generation would be a loss of $1,013,000. In Canada, the loss would be 64.3 GWh of energy and 2.92 MW of peak having a combined annual value of $1,301,000. In the U.S., there

would be a gain of 5.0 GWh of energy and a loss of 1.18 MW of peak which has an annual value of $371,000 for peak and giving a combined net gain of $288,000.

Plan 6L - The net annual effect on power generation would be a loss of $191,000 with a present worth of $2,208,000. In Canada, there would be a loss of 18.5 GWh of energy and 2.37 MW of peak with a combined annual value of $476,000. In the U.S., there would be a gain of 2.9 GWh of energy and a loss of 0.19 MW of peak giving a net annual gain of $285,000.

In summary, the plans would produce net annual losses to power generation of 1.6, 1.0, and 0.2 million dollars for Plans 25N, 15S and 6L respectively, which have present worth values of 18.0, 11.7 and 2.2 million dollars.

The following is a review of the effects of each regulation plan under Category 2 on each of the power systems involved.

7.3.2.1 Ontario Systems

The energy outputs from the Ontario plants were determined by the same method as Category 1. The outputs from the St. Marys River plants are the same as Category 1. The outputs from the Niagara River plants are essentially the same as Category 1, differing only by the effect of Lake Ontario elevation on the tailwater level at the SAB plants. The outputs from the Saunders St. Lawrence River plant reflect the benefits of Lake Ontario regulation under Category 2.

Plan 25N would result in a net annual loss of 57.8 GWh with an annual amortized value of $943,000. At the St. Lawrence plant, there would be a gain of 3.0 GWh compared with the base-of-comparison and a gain of 8.1 GWh over Category 1 due to the improved regulation of Lake Ontario.

Plan 15S would result in a net annual loss of 62.0 GWh with a value of $1,187,000. At the St. Lawrence, the gain would be 5.8 GWh compared to the basis-of-comparison and 5.3 GWh over Category 1.

Plan 6L would give a net annual loss of 19.7 GWh worth $407,000. The gain at the St. Lawrence would be 3.8 GWh compared with the base case and 4.9 GWh compared to Category 1.

The peak outputs from the Ontario plants were determined in the same way as under Category 1.

There would be a combined loss in peak load meeting capability of 4.45 MW, 2.92 MW and 2.37 MW for Plans 25N, 15S and 6L respectively, with annual values of $147,000, $97,000 and $78,000 (Tables E-14 and E-18).

7.3.2.2 Quebec System

On the Quebec system the economic evaluation of the different plans under Category 2 compared to the basis-of-comparison shows losses for Plans 25N

and 15S and a gain for Plan 6L. The annual and present worth values are shown in the following table:

Plan	Value of Gain (+) or Loss (-) Annual	Present Worth
25N	- $36,000	- $416,000
15S	- $17,000	- $197,000
6L	+ $ 9,000	+ $104,000

Plan 6L under Category 2 is the only plan that would bring a slight gain to the Quebec system.

7.3.2.3 New York State System

The effects of Category 2 (all plans) on energy production and capacity at Niagara would be the same as Category 1 and are discussed under 7.3.1.3.

At the St. Lawrence the effects of Category 2 on energy would be small, but positive, varying from a gain of 5.8 GWh for Plan 15S to 3.0 GWh for Plan 25N. The effects on capacity would be very minor varying from a loss of 0.9 MW for Plan 25N to a gain of 0.2 MW from Plan 6L. These results are shown on Table E-14.

The total economic effects on power, show a gain for two plans with Plans 15S and 6L being equally favourable at $0.28 million annually while Plan 25N would produce a yearly loss of $0.44 million as depicted in Table E-18.

7.3.2.4 Upper Michigan System

The peak and energy values would be the same as under Category 1.

7.3.3 Category 3 (Compared to the Basis-of-Comparison)

The peak and energy differences under Category 3, compared to the basis-of-comparison are summarized on Tables E-15 and E-19.

Plan 25N - The net annual effect on power generation would be a loss of $1,647,000 with a present worth value of $19,048,000. In Canada, the loss would be 76.1 GWh of energy and 2.43 MW of peak which has a combined annual value of $1,162,000. In the U.S., there would bea gain of 3.6 GWh of energy and a loss of 9.53 MW of peak resulting in a combined net annual loss of $485,000.

Plan 15S - The net annual effect on power generation would be a loss of $653,000 with a present worth value of $7,551,000. In Canada, the loss would be 72.3 GWh of energy and 3.06 MW of peak which has a combined annual value of $1,324,000. In the US, there would be an annual gain of

8.0 GWh of energy and a loss of 0.45 MW of peak resulting in a combined net annual gain of $671,000.

Plan 6L - The net annual effect on power generation would be a loss of $319,000 with a present worth value of $3,690,000. In Canada, there would be an annual loss of 28.0 GWh of energy and 5.57 MW of peak with an annual value of $641,000. In the U.S. there would be an annual gain of 3.1 GWh of energy and 0.02 MW of peak, resulting in a total annual gain of $322,000.

In summary, the net annual loss to power generation is 1.6, 0.7 and 0.3 million dollars for plans 25N, 15S and 6L respectively, with present worth values of 19.0, 7.6 and 3.7 million dollars.

The following is a review of the effects of each regulation plan under Category 3, compared to the basis-of-comparison, on each power system.

7.3.3.1 Ontario System

The energy losses at the St. Marys and Niagara River plants would be essentially the same as Category 1 as discussed in subsection 7.4.1. The effect at the St. Lawrence River plant, includes the combined effects of the St. Lawrence River channel excavations with the associated benefits of reduced channel losses between Lake Ontario and the powerhouse, and the Lake Erie regulation plans.

Plan 25N would result in a net annual energy loss of 58.6 GWh with an annual amortized value of $950,000. At the St. Lawrence, there is a gain of 2.3 GWh.

Plan 15S would result in a net annual loss of 57.5 GWh having a value of $1,111,000. At the St. Lawrence, there would be an annual gain of 8.8 GWh.

Plan 6L would result in a net loss of 18.7 GWh with an annual value of $387,000. The St. Lawrence would show a gain of 4.0 GWh.

The peak outputs were determined in the same way as Category 1. Under all three plans there is a loss in peak load meeting capability of 2.43 MW, 3.06 MW and 5.57 MW for Plans 25N, 15S and 6L respectively, which have annual values of $80,000, $101,000 and $184,000 (Tables E-15 and E-19).

7.3.3.2 Quebec System

On the Quebec system the economic evaluation of the different plans under Category 3 compared to the basis-of-comparison shows losses for each plan having annual and present worth values as follows:

Plan	Value of Loss (-) Annual	Present Worth
25N	-$132,000	-$1,527,000
15S	-$112,000	-$1,295,000
6L	-$ 70,000	-$ 810,000

7.3.3.3 New York State System

The effects of Category 3 (all plans) at Niagara would be identical to those described under 7.3.1.3 above.

At the St. Lawrence, the effects on energy would all be positive with Plan 15S showing an annual gain of 8.8 GWh. These benefits would accrue because average forebay elevation would be improved compared to the basis-of-comparison.

Effects on capacity would be minor, varying from a slight loss of 0.6 MW for Plan 25N to a slight gain of 0.8 MW for Plan 15S.

Overall economic effects for the Niagara and St. Lawrence plants would vary from a loss of $0.49 million annually to a gain of $0.66 million as shown in Table E-19.

7.3.3.4 Upper Michigan System

The peak and energy values would be the same as under Category 1.

7.3.4 Category 3 (Compared to the Adjusted Basis-of-Comparison)

In this section the peak and energy outputs computed for Category 3 are compared to the adjusted basis-of-comparison which eliminates the effect of operating Lake Ontario within the Orders of Approval from the effects of the Lake Erie regulation plans. The peak and energy differences compared to the adjusted basis-of-comparison are summarized on Table E-16 and the corresponding dollar values are shown on Table E-20.

Plan 25N - The net annual effect on power generation would be a loss of $2,044,000 which has a present worth value of $23,640,000. In Canada, the loss would be 73.0 GWh of energy and 0.45 MW of peak which has a combined annual value of $1,077,000. In the U.S., there would be a net loss of 0.5 GWh of energy and 9.94 MW of peak having a combined annual value of $957,000.

Plan 15S - The net annual effect on power generation would be a loss of $1,051,000 having a present worth value of $12,157,000. In Canada, the loss would be 69.3 GWh of energy and 0.17 MW of peak, having a net annual value of $1,240,000. In the U.S., there would be a net energy gain of 3.9 GWh and a loss of 0.86 MW of peak which would produce a combined annual gain of $189,000.

Plan 6L - The net annual effect on power generation would be a loss of $716,000 which has a present worth value of $8,280,000. In Canada, there would be an energy loss of 24.9 GWh and a peak loss of 2.68 MW which has a combined annual value of $556,000. In the U.S., there would be an annual energy loss of 1.0 GWh of energy and 0.39 MW of peak which have a combined annual value of $160,000.

In summary, the net annual loss to power generation is 2.0, 1.1 and 0.7 million dollars for Plans 25N, 15S and 6L which have present worth values of 23.6, 12.2 and 8.3 million dollars.

The following is a review of the effects of each Lake Erie regulation plan under Category 3, compared to the adjusted basis-of-comparison, on each power system.

7.3.4.1 Ontario System

The energy losses at the St. Marys and Niagara River plants are the same as those in Category 3 basis-of-comparison, as discussed in 7.3.3.1. At the St. Lawrence, however, the effect of regulating Lake Ontario within the "Orders of Approval" is eliminated and only the increase effect of the Lake Erie regulation plans is shown (Tables E-16 and E-20).

Plan 25N would result in a net annual loss of 62.7 GWh with an annual amortized value of $1,014,000. At the St. Lawrence River, there would be a loss of 1.8 GWh.

Plan 15S would result in a net annual loss of 61.6 GWh with an annual loss of $1,176,000. At the St. Lawrence River plant there would be a gain of 4.7 GWh.

Plan 6L would result in a net annual loss of 22.8 GWh which has an annual amortized value of $451,000. At the St. Lawrence River plant, there would be a small loss of 0.1 GWh.

The peak outputs were determined in the same way as in Category 1. Under Plan 25N, there would be an annual gain in peak load meeting capability of 0.45 MW with an annual value of $15,000. Under Plans 15S and 6L there would be an annual loss of 0.17 MW and 2.68 MW, respectively, which would have annual values of $6,000 and $89,000.

7.3.4.2 Quebec System

On the Quebec system the economic evaluation of the different plans under Category 3 compared to the adjusted basis-of-comparison shows losses having annual and present worth values as follows:

Plan	Value of Loss (-) Annual	Present Worth
25N	-$78,000	-$902,000
15S	-$58,000	-$671,000
6L	-$16,000	-$185,000

7.3.4.3 New York State System

At Niagara the effect of Category 3 compared to the adjusted basis-of-comparison are identical to those described under Subsection 7.3.1.3.

At the St. Lawrence Plan 15S would have a benefit of 4.7 GWh annually while Plan 25N would show a loss of 1.8 GWh. Effects on capacity at the St. Lawrence would be small, varying from a gain of 0.4 MW for Plan 15S to a loss of 1 MW for Plan 25N (Table E-16).

Under this category, the overall effects on NYS power would show losses of $0.98 million annually for Plan 25N and $0.16 million for Plan 6L. Plan 15S would show a gain of $0.19 million. Table E-20 summarizes these results.

7.3.4.4 Upper Michigan System

The peak and energy losses would be the same as under Category 1, Subsection 7.3.1.1.

Annex A

LIST OF MEMBERS AND ASSOCIATES OF POWER SUBCOMMITTEE

United States Section

Alvin Hollmer
Power Authority of the State of New York
Chairman, July 13, 1977 to completion

B.G. DeCooke
U.S. Army Corps of Engineers - Detroit District
Associate, July 13, 1977 to completion

Canadian Section

John M. Spratt
Ontario Hydro
Chairman, July 13, 1977 to completion

Robert Brisbois
Hydro Quebec
Member, July 13, 1977 to November 24, 1980

Jean-Claude Rassam
Hydro Quebec
Member, November 25, 1980 to completion

Annex B

CONVERSION FACTORS
(BRITISH TO METRIC UNITS)

1 cubic foot per second (cfs) = 0.028317 cubic metres per second (cms)

1 cfs-month = 0.028317 cms-month

1 foot = 0.30480 metres

1 inch = 2.54 centimetres

1 mile (statute) = 1.6093 kilometeres

1 ton (short) = 907.18 kilograms

1 square mile = 2.5900 square kilometres

1 cubic mile = 4.1682 cubic kilometres

Temperature in Celsius: $^{o}C = (^{o}F - 32)/1.8$

1 acre-feet = 1.233.5 cubic metres

1 gallon (U.S.) = 3.7853 litres

1 gallon (British) = 4.5459 litres

Annex C

RESULTS OF PEAK AND ENERGY DETERMINATIONS

This annex contains:

(1) Tablulations of the average annual energy production and peak outputs and the corresponding differences from the basis-of-comparison (Δ BOC) or from the adjusted basis-of-comparison (Δ ABOC).

(2) Details of the calculations of the adjustments to the energy differences (benefits/losses) that were required because of the differences in long-term mean outflows as discussed in Subsection 7.2, together with tabulations of these adjustments and the Δ BOC and ΔABOC after adjustment.

1. Average Annual Energy Production and Peak Outputs

The average annual energy production and peak outputs, that were computed in accordance with the methodology described in Sections 2 to 5 are presented together with the differences from the BOC or ABOC for each power system and for each category in the following tables:

Energy and Peak Outputs

Power System	Category	Table No	Page No
Ontario - Energy	1	1	E-97
	2	2	E-98
	3 compared to BOC	3	E-99
	3 compared to ABOC	4	E-100
Ontario - Peak	1 and 2	5	E-101
	3 compared to BOC	6	E-102
	3 compared to ABOC	7	E-103
Quebec - Energy	1, 2, and 3	8	E-104
Upper Michigan - Peak and Energy	1, 2, and 3	9	E-105
New York State - Peak and Energy (differences only)	1, 2, and 3	10	E-106

2. Details of Adjustments to Energy Differences (Benefits/Losses)

As explained in Subsection 7 it was necessary to adjust the energy differences (benefits/losses) that were computed for each generating station on the St. Marys, Niagara, and St. Lawrence Rivers to account for the difference in long term mean outflows of Lake Superior, Lake Erie, and Lake Ontario resulting from the regulation plans and from the basis-of-comparison (and adjusted basis-of-comparison).

The adjustments were calculated by multiplying the long term mean flow difference, shared equally between Canada and the U.S. except at Beauharnois-Les Cedres, by the appropriate incremental economy factor (Δ kW/cfs). The average kW thus computed was converted to average annual energy in GWh and added to, or subtracted from, the unadjusted energy differences.

The Δ kW/cfs values were calculated for the St. Marys and St. Lawrence River plants from the International Great Lakes Diversions and Consumptive Uses Study by determining the difference in average kilowatts between the basis-of-comparison and Scenario 5, and dividing this by the corresponding difference in long-term mean outflow. At the Niagara River plants the Δ kW/cfs value for the Ontario plants was computed especially for this study using an increment of 310 cfs. On the U.S. side no adjustment was required because of the methodolgy used to compute the energy differences.

The adjustment calculations are tabulated by river, for each power system and for each category and are shown together with the BOC or ABOC after adjustment on the following tables:

<u>Adjustment to Energy Differences</u>

River	System	Category	Table No	Page No
St. Marys	Ontario	1, 2, and 3	11	E-107
St. Marys	Upper Michigan	1, 2, and 3	12	E-108
Niagara	Ontario	1	13	E-109
		2	14	E-110
		3	15	E-111
St. Lawrence	Ontario or New York State	1	16	E-112
		2	17	E-113
		3 (compared to BOC)	18	E-114
		3 (compared to ABOC)	19	E-115
	Quebec system	1, 2, and 3 (compare to BOC) 3 (compare to ABOC)	20	E-116

Table 1

Power Evaluation - Category 1

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Ontario System

Difference in Average Annual Energy Production

		Average Annual Energy - (GWh)			Difference from BOC - (GWh)		
		Daytime	Nighttime	Totals	Daytime	Nighttime	Totals
BOC	St. Marys	262.2	131.1	393.3			
	Niagara	10,255.5	2,609.9	12,865.4			
	St. Lawrence	4,491.2	1,933.7	6,424.9			
	Total	15,008.9	4,674.7	19,683.6			
25N	St. Marys	263.7	131.9	395.6	+ 1.5	+ 0.8	+ 2.3
	Niagara	10,222.1	2,597.6	12,819.7	-33.4	-12.3	-45.7
	St. Lawrence	4,489.4	1,940.5	6,429.9	- 1.8	+ 6.8	+ 5.0
	Total	14,975.2	4,670.0	19,645.2	-33.7	- 4.7	-38.4
15S	St. Marys	263.1	131.6	394.7	+ 0.9	+ 0.5	+ 1.4
	Niagara	10,171.3	2,631.1	12,802.4	-84.2	+21.2	-63.0
	St. Lawrence	4,494.3	1,936.6	6,430.9	+ 3.1	+ 2.9	+ 6.0
	Total	14,928.7	4,699.3	19,628.0	-80.2	+24.6	-55.6
6L	St. Marys	262.4	131.2	393.6	+ 0.2	+ 0.1	+ 0.3
	Niagara	10,222.5	2,621.7	12,844.2	-33.0	+11.8	-21.2
	St. Lawrence	4,492.8	1,935.0	6,427.8	+ 1.6	+ 1.3	+ 2.9
	Total	14,977.7	4,687.9	19,665.6	-31.2	+13.2	-18.0

Table 2

Power Evaluation - Category 2

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Ontario System

Difference in Average Annual Energy Production

		Average Annual Energy - (GWh)			Difference from BOC - (GWh)		
		Daytime	Nighttime	Totals	Daytime	Nighttime	Totals
BOC	St. Marys	262.2	131.1	393.3			
	Niagara	10,255.5	2,609.9	12,865.4			
	St. Lawrence	4,491.2	1,933.7	6,424.9			
	Total	15,008.9	4,674.7	19,683.6			
25N	St. Marys	263.7	131.9	395.6	+ 1.5	+ 0.8	+ 2.3
	Niagara	10,220.9	2,596.9	12,817.8	-34.6	-13.0	-47.6
	St. Lawrence	4,492.6	1,943.3	6,435.9	+ 1.4	+ 9.6	+11.0
	Total	14,977.2	4,672.1	19,649.3	-31.7	- 2.6	-34.3
15S	St. Marys	263.1	131.6	394.7	+ 0.9	+ 0.5	+ 1.4
	Niagara	10,170.8	2,630.7	12,801.5	-84.7	+20.8	-63.9
	St. Lawrence	4,495.4	1,938.6	6,434.0	+ 4.2	+ 4.9	+ 9.1
	Total	14,929.3	4,700.9	19,630.2	-79.6	+26.2	-53.4
6L	St. Marys	262.4	131.2	393.6	+ 0.2	+ 0.1	+ 0.3
	Niagara	10,222.2	2,621.5	12,843.7	-33.3	+11.6	-21.7
	St. Lawrence	4,493.8	1,936.5	6,430.3	+ 2.6	+ 2.8	+ 5.4
	Total	14,978.4	4,689.2	19,667.6	-30.5	+14.5	-15.8

Table 3

Power Evaluation - Category 3

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Ontario System

Difference in Average Annual Energy Production

		Average Annual Energy - (GWh)			Difference from BOC - (GWh)		
		Daytime	Nighttime	Totals	Daytime	Nighttime	Totals
BOC	St. Marys	262.2	131.1	393.3			
	Niagara	10,255.5	2,609.9	12,865.4			
	St. Lawrence	4,491.2	1,933.7	6,424.9			
	Total	15,008.9	4,674.7	19,683.6			
25N	St. Marys	263.7	131.9	395.6	+ 1.5	+ 0.8	+ 2.3
	Niagara	10,220.9	2,596.8	12,817.7	-34.6	-13.1	-47.7
	St. Lawrence	4,493.5	1,941.9	6,435.4	+ 2.3	+ 8.2	+10.5
	Total	14,978.1	4,670.6	19,648.7	-30.8	- 4.1	-34.9
15S	St. Marys	263.1	131.6	394.7	+ 0.9	+ 0.5	+ 1.4
	Niagara	10,171.7	2,631.3	12,803.0	-83.8	+21.4	-62.4
	St. Lawrence	4,499.1	1,938.3	6,437.4	+ 7.9	+ 4.6	+12.5
	Total	14,933.9	4,701.2	19,635.1	-75.0	+26.5	-48.5
6L	St. Marys	262.4	131.2	393.6	+ 0.2	+ 0.1	+ 0.3
	Niagara	10,222.7	2,621.8	12,844.5	-32.8	+11.9	-20.9
	St. Lawrence	4,495.4	1,935.7	6,431.1	+ 4.2	+ 2.0	+ 6.2
	Total	14,980.5	4,688.7	19,669.2	-28.4	+14.0	-14.4

Table 4

Power Evaluation - Category 3

Regulation Plans 25N, 15S and 6L Compared to Adjusted Basis-of-Comparison (ABOC)

Ontario System

Difference in Average Annual Energy Production

		Average Annual Energy - (GWh)			Difference from ABOC - (GWh)		
		Daytime	Nighttime	Totals	Daytime	Nighttime	Totals
ABOC	St. Marys	262.2	131.1	393.3			
	Niagara	10,255.5	2,609.9	12,865.4			
	St. Lawrence	4,494.6	1,935.1	6,429.7			
	Total	15,012.3	4,676.1	19,688.4			
25N	St. Marys	263.7	131.9	395.6	+ 1.5	+ 0.8	+ 2.3
	Niagara	10,220.9	2,596.8	12,817.7	-34.6	-13.1	-47.7
	St. Lawrence	4,493.5	1,941.9	6,435.4	- 1.1	+ 6.8	+ 5.7
	Total	14,978.1	4,670.6	19,648.7	-34.2	- 5.5	-39.7
15S	St. Marys	263.1	131.6	394.7	+ 0.9	+ 0.5	+ 1.4
	Niagara	10,171.7	2,631.3	12,803.0	-83.6	+21.4	-62.4
	St. Lawrence	4,499.1	1,938.3	6,437.4	+ 4.5	+ 3.2	+ 7.7
	Total	14,933.9	4,701.2	19,635.1	-78.4	+25.1	-53.3
6L	St. Marys	262.4	131.2	393.6	+ 0.2	+ 0.1	+ 0.3
	Niagara	10,222.7	2,621.8	12,844.5	-32.8	+11.9	-20.9
	St. Lawrence	4,495.4	1,935.7	6,431.1	+ 0.8	+ 0.6	+ 1.4
	Total	14,980.5	4,688.7	19,669.2	-31.8	+12.6	-19.2

Table 5

Power Evaluation - Category 1 and 2

Regulation Plans 25N, 15S, and 6L Compared to Basis-of-Comparison (BOC)

Ontario System

Difference in Peak Load Meeting Capability

			25N		15S		6L	
		BOC	CAT. 1	CAT. 2	CAT. 1	CAT. 2	CAT. 1	CAT. 2
MEAN	- MW	3,008.17	3,007.77	3,004.18	3,008.49	3,005.35	3,008.97	3,005.83
ST. DEV.	- MW	66.5889	74.9809	76.2878	68.8674	68.8214	67.4290	67.1835
Δ LMC_{MH}	- MW	-	-0.40	-3.99	0.32	-2.82	0.80	-2.34
Δ V_H		-	-1,188.05	-1,385.75	-308.63	-302.30	-112.59	-79.53
Δ LMC_{VH}	- MW	-	-0.3960	-0.4619	-0.1029	-0.1008	-0.0375	-0.0265
$\Sigma(\Delta LMC)$	- MW	-	-0.80	-4.45	0.22	-2.92	0.76	-2.37

NOTE: $\Sigma(\Delta LMC)$ = Difference in peak load meeting capability
= Difference in December hydraulic mean + difference in December hydraulic variance
= $\Delta LMC_{MH} + \Delta LMC_{VH}$

Table 6

Power Evaluation - Category 3

Regulation Plans 25N, 15S, and 6L Compared to Basis-of-Comparison (BOC)

Ontario System

Difference in Peak Load Meeting Capability

		BOC	25N CAT. 3	15S CAT. 3	6L CAT. 3
MEAN	- MW	3008.17	3005.78	3005.25	3003.10
ST. DEV.	- MW	66.5889	67.5679	69.6191	76.9860
ΔLMC_{MH}	- MW	-	-2.39	-2.92	-5.07
ΔV_H		-	131.34	412.74	1492.76
ΔLMC_{VH}	- MW	-	-0.0438	-0.1376	-0.4976
$\Sigma(\Delta LMC)$	- MW	-	-2.43	-3.06	-5.57

NOTE: $\Sigma(\Delta LMC)$ = Difference in peak load meeting capability
= Difference in December hydraulic mean + difference in December hydraulic variance
= $\Delta LMC_{MH} + \Delta LMC_{VH}$

Table 7

Power Evaluation - Category 3

Regulation Plans 25N, 15S, and 6L Compared to Adjusted Basis-of-Comparison (ABOC)

Ontario System

Difference in Peak Load Meeting Capability

	ABOC	25N CAT. 3	15S CAT. 3	6L CAT. 3
MEAN - MW	3,005.30	3,005.78	3,005.25	3,003.10
ST. DEV. - MW	66.9389	67.5679	69.6191	76.9860
Δ LMC_{MH} - MW	-	0.48	-0.05	-2.20
Δ V_H	-	84.60	366.00	1,446.03
Δ LMC_{VH} - MW	-	-0.0282	-0.1220	-0.4820
$\Sigma(\Delta LMC)$ - MW	-	0.45	-0.17	-2.68

NOTE: $\Sigma(\Delta LMC)$ = Difference in peak load meeting capability
= Difference in December hydraulic mean + difference in December hydraulic variance
= $\Delta LMC_{MH} + \Delta LMC_{VH}$

Table 8

Power Evaluation - Category 1, 2 and 3

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

and Adjusted Basis-of-Comparison (ABOC)

Quebec System

Difference in Average Annual Energy Production

	Average Annual Energy - GWh	Difference from BOC - GWh	Difference from ABOC - GWh
BOC	11,501.8		
ABOC	11,496.4		
Category 1			
25N	11,513.0	+11.2	
15S	11,506.9	+ 5.1	
6L	11,507.2	+ 5.4	
Category 2			
25N	11,512.0	+10.2	
15S	11,506.4	+ 4.6	
6L	11,506.8	+ 5.0	
Category 3			
25N	11,499.0	- 2.8	+ 2.6
15S	11,493.9	- 7.9	- 2.5
6L	11,497.1	- 4.7	+ 0.7

Table 9

Power Evaluation - Category 1, 2 and 3

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

Upper Michigan System

Difference in Average Annual Energy Production
and
Peak Load Meeting Capability

			Difference from BOC	
	Average Annual Energy - GWh	Peak Capacity - MW	Average Annual Energy - GWh	Peak Capacity - MW
BOC	379.3	29.26		
25N	381.6	29.32	+ 2.3	+ 0.06
15S	381.1	29.28	+ 1.8	+ 0.02
6L	379.5	29.27	+ 0.2	+ 0.01

Table 10

Power Evaluation - Category 1

Regulation Plans 25N, 15S and 6L Compared to Basis-of-Comparison (BOC)

and Adjusted Basis-of-Comparison (ABOC)

New York State System

Difference in Average Annual Energy Production
and
Peak Load Meeting Capability

		Difference from BOC						Difference from ABOC	
		Category 1		Category 2		Category 3		Category 3	
		Avg. Annual Energy GWh	Peak Capacity MW	Avg. Annual Energy GWh	Peak Capacity MW	Avg. Annual Energy GWh	Peak Capacity MW	Avg. Annual Energy GWh	Peak Capacity MW
25N	Niagara	-0.7	-9.0	-0.7	-9.0	-0.7	-9.0	-0.7	-9.0
	St. Lawrence	+5.0	-1.4	+11.0	-0.9	+10.5	-0.59	+5.7	-1.0
	Total	+4.3	-10.4	+10.3	-9.9	+9.8	-9.59	+5.0	-10.0
15S	Niagara	-2.5	-1.3	-2.5	-1.3	-2.5	-1.3	-2.5	-1.3
	St. Lawrence	+6.0	+0.2	+9.1	+0.1	+12.5	+0.83	+7.7	+0.43
	Total	+3.5	-1.1	+6.6	-1.2	+10.0	-0.47	+5.2	-0.88
6L	Niagara	-1.1	-0.4	-1.1	-0.4	-1.1	-0.4	-1.1	-0.4
	St. Lawrence	+2.9	+0.2	+5.4	+0.2	+6.2	+0.41	+1.4	0.0
	Total	+1.8	-0.2	+4.3	-0.2	+5.1	+0.01	+0.3	-0.4

Table 11

Power Evaluation - Category 1, 2 and 3

Ontario System - St. Marys River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Superior Mean Outflow from Basis-of-Comparison (BOC) = 77,818 c.f.s.

Regulation Scheme	Lake Superior Mean Outflow from Regulation Scheme cfs	Difference from BOC Total cfs	Difference from BOC Canada Share cfs	Incremental Economy Factor kW/cfs	Average Annual Energy Adjustment GWh		Average Annual Energy Δ BOC Before Adjustment GWh	Average Annual Energy Δ BOC After Adjustmen GWh
25N	77,872	+ 54	+ 27	0.31	day	-0.1	+1.5	+1.4
					night	0	+0.8	+0.8
					total	-0.1	+2.3	+2.2
15S	77,845	+ 27	+ 14	0.31	day	0	+0.9	+0.9
					night	0	+0.5	+0.5
					total	0	+1.4	+1.4
6L	77,825	+ 7	+ 4	0.31	day	0	+0.2	+0.2
					night	0	+0.1	+0.1
					total	0	+0.3	+0.3

Table 12

Power Evaluation - Category 1, 2 and 3

Upper Michigan - St. Marys River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Superior Mean Outflow from Basis-of-Comparison (BOC) = 77,818 c.f.s.

	Lake Superior Mean Outflow				Average Annual Energy		
	from	Difference from BOC		Incremental		Δ BOC	Δ BOC
Regulation Scheme	**Regulation Scheme**	**Total**	**U.S. Share**	**Economy Factor**	**Adjustment**	**Before Adjustment**	**After Adjustment**
	cfs	cfs	cfs	kW/cfs	GWh	GWh	GWh
25N	77,872	+ 54	+ 27	0.887	-0.2	+2.3	+2.0
15S	77,845	+ 27	+ 14	0.887	-0.1	+1.8	+1.7
6L	77,825	+ 7	+ 4	0.887	0	+0.2	+0.2

Table 13

Power Evaluation - Category 1

Ontario System - Niagara River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Erie Mean Outflow from Basis-of-Comparison (BOC) = 207,175 c.f.s.

Regulation Scheme	Lake Erie Mean Outflow from Regulation Scheme	Difference from BOC Total	Difference from BOC Canada Share	Incremental Economy Factor	Average Annual Energy Adjustment		Average Annual Energy Δ BOC Before Adjustment	Average Annual Energy Δ BOC After Adjustment
	cfs	cfs	cfs	kW/cfs		GWh	GWh	GWh
25N	207,481	+306	+153	11.484	day	-10.3	-33.4	-43.7
					night	- 5.1	-12.3	-17.4
					total	-15.4	-45.7	-61.1
15S	207,281	+106	+ 53	11.484	day	- 3.5	-84.2	-87.7
					night	- 1.8	+21.2	+19.4
					total	- 5.3	-63.0	-68.3
6L	207,216	+ 41	+ 20	11.484	day	- 1.4	-33.0	-34.4
					night	- 0.7	+11.8	+11.1
					total	- 2.1	-21.2	-23.3

Table 14

Power Evaluation - Category 2

Ontario System - Niagara River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Erie Mean Outflow from Basis-of-Comparison (BOC) = 207,175 c.f.s.

Regulation Scheme	Lake Erie Mean Outflow from Regulation Scheme	Lake Erie Mean Outflow Difference from BOC: Total	Lake Erie Mean Outflow Difference from BOC: Canada Share	Incremental Economy Factor	Average Annual Energy: Adjustment		Average Annual Energy: Δ BOC Before Adjustment	Average Annual Energy: Δ BOC After Adjustment
	cfs	cfs	cfs	kW/cfs		GWh	GWh	GWh
25N	207,481	+306	+153	11.484	day	-10.3	-34.6	-44.9
					night	- 5.1	-13.0	-18.1
					total	-15.4	-47.6	-63.0
15S	207,281	+106	+ 53	11.484	day	- 3.5	-84.7	-88.2
					night	- 1.8	+20.8	+19.0
					total	- 5.3	-63.9	-69.2
6L	207,216	+ 41	+ 20	11.484	day	- 1.4	-33.3	-34.7
					night	- 0.7	+11.6	+10.9
					total	- 2.1	-21.7	-23.8

Table 15

Power Evaluation - Category 3

Ontario System - Niagara River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Erie Mean Outflow from Basis-of-Comparison (BOC) = 207,175 c.f.s.

	Lake Erie Mean Outflow				Average Annual Energy			
Regulation Scheme	from Regulation Scheme	Difference from BOC: Total	Difference from BOC: Canada Share	Incremental Economy Factor	Adjustment		Δ BOC Before Adjustment	Δ BOC After Adjustment
	cfs	cfs	cfs	kW/cfs		GWh	GWh	GWh
25N	207,481	+306	+153	11.484	day	-10.3	-34.6	-44.9
					night	- 5.1	-13.1	-18.2
					total	-15.4	-47.7	-63.1
15S	207,281	+106	+ 53	11.484	day	- 3.5	-83.8	-87.3
					night	- 1.8	+21.4	+19.6
					total	- 5.3	-62.4	-67.7
6L	207,216	+ 41	+ 20	11.484	day	- 1.4	-32.8	-34.2
					night	- 0.7	+11.9	+11.2
					total	- 2.1	-20.9	-23.0

Table 16

Power Evaluation - Category 1

Ontario or New York State System - St. Lawrence River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Ontario Mean Outflow from Basis-of-Comparison (BOC) = 242,089 c.f.s.

Regulation Scheme	Lake Ontario Mean Outflow: from Regulation Scheme	Difference from BOC: Total	Difference from BOC: Can. or U.S. Share	Incremental Economy Factor	Average Annual Energy: Adjustment		Average Annual Energy: Δ BOC Before Adjustment	Average Annual Energy: Δ BOC After Adjustment
	cfs	cfs	cfs	kW/cfs		GWh	GWh	GWh
25N	242,513	+424	+212	5.44	day	- 6.7	-1.8	-8.5
					night	- 3.4	+6.8	+3.4
					total	-10.1	+5.0	-5.1
15S	242,321	+232	+116	5.44	day	- 3.7	+3.1	-0.6
					night	- 1.8	+2.9	+1.1
					total	- 5.5	+6.0	+0.5
6L	242,258	+169	+ 84	5.44	day	- 2.7	+1.6	-1.1
					night	- 1.3	+1.3	0
					total	- 4.0	+2.9	-1.1

Table 17

Power Evaluation - Category 2

Ontario or New York State System - St. Lawrence River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Ontario Mean Outflow from Basis-of-Comparison (BOC) = 242,089 c.f.s.

Regulation Scheme	Lake Ontario Mean Outflow from Regulation Scheme	Difference from BOC Total	Difference from BOC Can. or U.S. Share	Incremental Economy Factor	Average Annual Energy Adjustment		Average Annual Energy Δ BOC Before Adjustment	Average Annual Energy Δ BOC After Adjustment
	cfs	cfs	cfs	kW/cfs		GWh	GWh	GWh
25N	242,423	+334	+167	5.44	day	-5.3	+ 1.4	-3.9
					night	-2.7	+ 9.6	+6.9
					total	-8.0	+11.0	+3.0
15S	242,228	+139	+ 70	5.44	day	-2.2	+ 4.2	+2.0
					night	-1.1	+ 4.9	+3.8
					total	-3.3	+ 9.1	+5.8
6L	242,157	+ 68	+ 34	5.44	day	-1.1	+ 2.6	+1.5
					night	-0.5	+ 2.8	+2.3
					total	-1.6	+ 5.4	+3.8

Table 18

Power Evaluation - Category 3

Ontario or New York State System - St. Lawrence River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Ontario Mean Outflow from Basis-of-Comparison (BOC) = 242,089 c.f.s.

Regulation Scheme	Lake Ontario Mean Outflow from Regulation Scheme	Difference from BOC: Total	Difference from BOC: Can. or U.S. Share	Incremental Economy Factor	Average Annual Energy: Adjustment		Average Annual Energy: Δ BOC Before Adjustment	Average Annual Energy: Δ BOC After Adjustment
	cfs	cfs	cfs	kW/cfs		GWh	GWh	GWh
25N	242,435	+346	+173	5.44	day	-5.5	+ 2.3	-3.2
					night	-2.7	+ 8.2	+5.5
					total	-8.2	+10.5	+2.3
15S	242,243	+154	+ 77	5.44	day	-2.4	+ 7.9	+5.5
					night	-1.3	+ 4.6	+3.3
					total	-3.7	+12.5	+8.8
6L	242,183	+ 94	+ 47	5.44	day	-1.5	+ 4.2	+2.7
					night	-0.7	+ 2.0	+1.3
					total	-2.2	+ 6.2	+4.0

Table 19

Power Evaluation - Category 3

Ontario or New York State System - St. Lawrence River Plants

Adjustment to Average Annual Energy
for Difference in Mean Outflow

Lake Ontario Mean Outflow from Adjusted Basis-of-Comparison (ABOC) = 242,118 c.f.s.

Regulation Scheme	Lake Ontario Mean Outflow: from Regulation Scheme	Difference from ABOC: Total	Difference from ABOC: Can. or U.S. Share	Incremental Economy Factor	Average Annual Energy: Adjustment		Average Annual Energy: Δ ABOC Before Adjustment	Average Annual Energy: Δ ABOC After Adjustment
	cfs	cfs	cfs	kW/cfs		GWh	GWh	GWh
25N	242,435	+317	+158	5.44	day	-5.0	-1.1	-6.1
					night	-2.5	+6.8	+4.3
					total	-7.5	+5.7	-1.8
15S	242,243	+125	+ 62	5.44	day	-2.0	+4.5	+2.5
					night	-1.0	+3.2	+2.2
					total	-3.0	+7.7	+4.7
6L	242,183	+ 65	+ 32	5.44	day	-1.0	+0.8	-0.2
					night	-0.5	+0.6	+0.1
					total	-1.5	+1.4	-0.1

Table 20

Power Evaluation - Category 1, 2 and 3

Quebec System - St. Lawrence River Plants

Adjustment to Average Annual Energy for Difference in Mean Outflow

Lake Ontario Mean Outflow from Basis-of-Comparison (BOC) = 242,068 c.f.s.
Adjusted Basis-of-Comparison (ABOC) = 242,111 c.f.s.

	Regulation Scheme	Lake Mean Outflow from Regulation Scheme cfs	Difference from BOC or ABOC Total cfs	Difference from BOC or ABOC Share cfs	Incremental Economy Factor kW/cfs	Average Annual Energy Adjustment GWh	Δ Before Adjustment GWh	Δ After Adjustment GWh
	Compared to BOC							
Category 1	25N	242,517	+449	+449	4.7	-18.5	-11.2	- 7.3
	15S	242,317	+249	+249	4.7	-10.3	+ 5.1	- 5.2
	6L	242,263	+195	+195	4.7	- 8.0	+ 5.4	- 2.6
Category 2	25N	242,430	+362	+362	4.7	-14.9	+10.2	- 4.7
	15S	242,236	+168	+168	4.7	- 6.9	+ 4.6	- 2.3
	6L	242,160	+ 92	+ 92	4.7	- 3.8	+ 5.0	+ 1.2
Category 3	25N	242,425	+357	+357	4.7	-14.7	- 2.8	-17.5
	15S	242,236	+168	+168	4.7	- 6.9	- 7.9	-14.8
	6L	242,179	+111	+111	4.7	- 4.6	- 4.7	- 9.3
	Compared to ABOC							
Category 3	25N	242,425	+314	+314	4.7	-12.9	+ 2.6	-10.3
	15S	242,236	+125	+125	4.7	- 5.2	- 2.5	- 7.7
	6L	242,179	+ 68	+ 68	4.7	- 2.8	+ 0.7	- 2.1

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